Delaware Energy Initiative

April 8, 2003

Delaware Energy Task Force
Transmission and Distribution Work Group

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Executive Summary

OBJECTIVES

Based on Executive Order No. 31, "Creation of Delaware Energy Task Force," a Transmission and Distribution Work Group, led by the Delaware Public Service Commission ("PSC") Chair McRae, was formed to examine the following specific objectives.

1. Increase transmission capacity in existing rights-of-way.
2. Develop new transmission lines to provide natural gas to western and eastern Sussex County.
3. Upgrade transmission lines below the C & D Canal to increase capacity to transport additional electricity supply from other parts of the PJM, Interconnection L.L.C. ("PJM") transmission grid and eliminate congestion on the Delmarva Peninsula.

APPROACH

The Work Group started by brainstorming key issues that are known to impact the availability of transmission and distribution capacity on the peninsula. After identifying five (5) key issues, Work Group members volunteered to review areas of interest, to provide a straw position paper on critical concerns, and to provide recommendations by which Delaware could work to achieve the energy capacity objectives. The resulting material formed the basis of a draft report that was assembled, reviewed and provided to the project consultant, Applied Energy.

The report examines "**energy**"[1] capacity issues, concentrating on electric and natural gas. It includes a short background on transmission and distribution capacity as it exists in Delaware and highlights eight (8) major issues that have significant impact on Delaware's ability to develop and expand energy transport capacity to meet future consumer needs. Within each issue is a discussion of the topic and suggested policy recommendations.

TRANSMISSION & DISTRIBUTION IN DELAWARE

Electric and gas transmission and distribution in Delaware is the responsibility of many different groups, including PJM, individual energy companies and federal and state regulatory agencies. It is a difficult process to ensure both adequacy of energy and the continuance of low energy costs for Delaware consumers due to several factors.

1. Diversity of federal, state, public and private responsibility for facilities
2. Inability to meet consumer energy needs in different forms (interchangeability)
3. Lack of a coordinated Delaware or regional energy planning function,
4. Need for assurances/mechanisms for equitable investment cost recovery
5. Limited business incentive for alternatives such as electric energy supply
6. Various environmental/land use restrictions
7. Investment risks associated with new, restructured business rules

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[1] Reference to "energy" in this report broadly includes electric, natural gas, propane, oil, coal, nuclear, or renewables that provide usable power to consumers, usually in the form of heat or electricity. Reference to specific types of energy supply, transmission or distribution will be specifically identified or include the appropriate descriptor.

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Various portions of the energy industry were deregulated in 1999 and the continued evolution of this process has resulted in new merchant supply and transmission companies in competition with regulated entities. Deregulation, with new marketplace rules, forms the foundation upon which the new energy companies will make business investment decisions and which will establish energy service levels consistent with market value.

DELAWARE CONCERNS

1. Delaware population growth exceeds U.S. averages, particularly in Sussex County where growth has averaged approximately 3% per year.[2] In similar fashion, Delaware energy capacity requirements have averaged a 2.1% growth rate. New investment for system growth will be essential to meet the energy needs of new and existing consumers.

2. Electric transmission planning is conducted by PJM in cooperation with the individual member energy companies. Gas and electric distribution planning is company based, to meet their individual customer needs. There are no Delaware or regional entities responsible for consolidated "energy" planning.

3. Electric transmission planning is based on established reliability standards with only recent regard for economic impact. Off-cost generation[3], required due to system congestion, has occurred approximately 10-15% of the time[4]. When transmission congestion exists, energy costs may be significantly higher across the entire Delmarva Peninsula; therefore, PJM is currently reviewing the possibility of establishing an economic planning process to supplement standard reliability planning and to help mitigate congestion costs.

4. Delaware energy consumers expect to have reliable energy supplies at reasonable prices. Electric and gas utilities have routinely provided a quality level of reliability while regulation and rate caps ensured reasonable pricing. With the deregulation of the electric industry and the expiration of electric rate caps in 2005/2006, electric distribution companies could recover congestion and supply cost increases via rate proceedings that may escalate consumer energy costs.

5. The regional nature of electric and gas energy flows has broad impact well beyond Delaware's borders. Maryland and Virginia policies can significantly impact Delaware energy issues and vice versa. Close regional coordination may benefit all consumers in the region.

6. For companies willing to make infrastructure investment in a restructured business environment with regulated rate caps, there is the potential risk of not securing cost recovery via rate proceedings. Regulated investment recovery mechanisms continue to be limited to conventional rate processes.

7. Congested electric operations and related economic consequences have become more apparent on the Delmarva Peninsula with the implementation of PJM's locational

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[2] 2000 U.S. Census Report

[3] Off-cost generation is generation that is dispatched out of normal economic order, typically the selection of a specific generator at a higher cost than the next least expensive generator on the system.

[4] PJM Delmarva Peninsula Congestion Study (Attachment C)

marginal pricing ("LMP"). Under this pricing scheme transmission constraints or operating limits have required dispatch of higher cost generation to assure operational reliability. To limit these constraints, additional investment in either generation or transmission facilities will be necessary.

8. Gas transmission expansion is dependent on customers willing to pay the cost of the expansion. Under current investment practices there are limited incentives to provide this energy source in rural Delaware areas.

9. Routine coordination among utilities for maintenance and operational concerns is limited. Maintenance outages and operating guidelines often result in extended periods of congestion and increased energy costs.

10. Energy transport mechanisms are spread across large areas of Delaware and potentially subject to natural or man-made disasters. The application of new technologies for system monitoring and the development of new coordinated approaches to energy related emergencies have been limited by availability of resources.

11. Siting and permitting for new or upgraded facilities is a complex process requiring coordination with multiple agencies, communities and individuals. Even the additional or expanded use of existing rights-of-way requires a similar process. There is no eminent domain for the construction of electric facilities, which may result in more costly investments and delays in project completion.

12. New regulations and business practices are being proposed across all areas of the energy spectrum. The Federal Energy Regulatory Commission ("FERC") and state regulatory agencies are proposing new Standard Market Design ("SMD") and Generator Interconnection rules. PJM is proposing new merchant transmission business rules. The industry is in a continual state of change, and these changes will undoubtedly impact the price and availability of energy for Delaware consumers.

RECOMMENDATIONS

Work Group recommendations have been classified as either "Critical" or "Important." Critical recommendations are essential to an effective energy policy for managing transmission and distribution issues. Important recommendations are those that should be considered for a more complete and effective energy management process.

CRITICAL RECOMMENDATIONS

1. Delaware should maintain, and enhance where possible, the energy management process, ensuring continued reliable, cost-effective electric/gas supply and transmission infrastructure, and continuing to meet anticipated consumer load growth requirements.

2. Delaware should establish a State Energy Coordination Stakeholder Group that monitors Delaware's energy transport systems, drafts and implements actions necessary to enhance energy systems, and provides energy counsel to the Governor's Office and the recommended Multi-State Energy Commission to promote an economic, reliable and competitive energy market for all Delaware consumers.

3. Delaware should simplify the permitting, siting and right-of-way acquisition process by establishing a single agency with coordination and approval responsibilities. Encourage the agency to actively participate in property rights negotiations that have the potential to delay important Delaware energy investments.

4. Delaware should ensure there is an investment recovery process that provides regulated utilities with fair and equitable returns and does not hinder unregulated utilities from achieving a return commensurate with the level of business risk and consistent with the new marketplace rules/practices.

5. Delaware agencies (particularly, the Delaware Emergency Management Agency) should continue to coordinate with Homeland Security and others appropriate agencies to assure the security of existing energy transport facilities.

<u>IMPORTANT RECOMMENDATIONS</u>

1. Delaware should help facilitate the establishment of a Multi-State Energy Commission that, in coordination with federal, state, and regional agencies, utilities and energy consumers, identifies and, where appropriate, mandates and finances the infrastructure requirements needed to ensure the long-term sustainability of cost competitive energy supply, transport and delivery on the Delmarva Peninsula. The Commission should:

   - involve all interested stakeholder representatives,
   - establish energy supply needs,
   - identify critical supply, transport, transmission and distribution requirements,
   - provide investment incentives or assurances of investment recovery,
   - monitor the status of the regional energy system,
   - have sufficient resources to manage a multi-state energy initiative, and
   - ensure an integrated planning process that considers both reliability and congestion costs.

2. Delaware should encourage the development and use of energy capacity alternatives by providing economic incentives, incorporating the use of alternatives in the regional energy planning process, and when necessary mandating beneficial programs.

3. Delaware regulatory agencies should support the development and application of new cost-effective technologies for energy transport facilities.

4. Delaware should encourage and support proactive communications among Transmission Owners ("TOs"), Load Serving Entities ("LSEs") and PJM through the development of a working group to examine operational opportunities to minimize congestion, especially during planned maintenance outages.

FURTHER REVIEW

The Transmission and Distribution Work Group agreed that there are several key areas that would benefit from additional review. These include the following.

- Potential enhancements to PJM's LMP pricing mechanism to limit generator cost recovery during extensive periods of congestion
- A possible failsafe regulatory mechanism, if reliability of service were to deteriorate or congestion costs were to continue at high levels
- Mechanisms to more effectively manage both reliability and economic impact via a regional coordinated multi-state effort
- Potential approaches to encourage new electric and gas transmission investment, both regulated and merchant
    - § Incentive pricing
    - § Recovery assurances
    - § Rate of return protection
    - § State funding/surcharge
- Methods to encourage load management/demand response within the retail and wholesale customer base
- Revisions to current House Bill 10 legislation to include FERC 7 Factor Test[5]

CONCLUSION

The energy needs of Delaware are being managed by a broad spectrum of regulatory agencies in concert with free market dynamics. It is essential that Delaware energy policy include a comprehensive energy management process, which incorporates these various viewpoints, assumes a broad regional view of energy needs and which has the authority and resources to direct regional energy initiatives.

The use of a Multi-State Energy Commission, which closely coordinates with existing state energy agencies, PJM and FERC provides an effective tool to ensure the continuance of adequate, reasonably priced energy availability. In addition, the assignment of a single Delaware agency to assume energy responsibility, in close coordination with the Multi-State Energy Commission and other state agencies, simplifies the energy management process and provides focus on energy issues. The establishment of these agencies and enhancements to the energy management process may require supplemental legislation, particularly to help clarify state agency authority and to create the single state agency and Multi-State Commission.

There are many other ways to enhance the energy management process, including the encouragement of capacity alternatives and revised policies to simplify existing processes and stimulate new investment. New ways to fund transmission facilities and mechanisms to reduce financial risk are but a few of the ideas needing further review and discussion. In its simplest form, Delaware needs to have a well coordinated, cohesive set of policies and the legislative authority that establishes a high level regional planning process and an effective implementation mechanism to maintain reasonably priced energy adequacy.

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[5] Seven factors identified by FERC that form the basis of decisions on whether facilities are transmission or distribution.

Economic, clean and reliable energy is critical to the industries, businesses and citizens of the State of Delaware. Energy is essential to ensure continuous, long-term economic growth and development. The availability of energy is dependent on many variables including actual supply (generator and fuel availability), transmission and distribution capability/capacity, and the willingness of consumers to accept demand response programs (foregoing energy needs during periods of high price and limited availability). This section of the Delaware Energy Initiative deals primarily with electric and gas transmission and distribution capacity issues, and is but one step in the process of securing the appropriate energy needs for consumers in Delaware.

BACKGROUND

Work Group Objectives

As a result of the Governors Executive Order No. 31, "Creation of Delaware Energy Task Force," a Transmission and Distribution Work Group was assembled with a goal to formulate ways to ensure that energy[6] infrastructure will meet Delaware's future needs for transporting energy resources. More specifically, the Work Group was tasked to:

1. Increase transmission capacity in existing rights-of-way;
2. Develop new transmission lines to provide natural gas to western and eastern Sussex County; and
3. Upgrade transmission lines below the C & D Canal to increase capacity to transport additional electricity supply from other parts of the PJM transmission grid and eliminate congestion on the Delmarva Peninsula.

The Work Group believes that it may be more cost-effective to "reduce" congestion rather than "eliminate" it. Elimination may require excessive investment without corresponding benefit.

Structure and Activities

The Transmission and Distribution Work Group, chaired by the Delaware Public Service Commission ("PSC") Chair McRae, consisted of a diverse group of approximately 35 individuals (Attachment A). After initially dividing into two subgroups, key issues related to the transmission and distribution of energy were brainstormed. The list was refined and subgroup members volunteered to work on each of the five (5) main areas. Subsequent to their work, each group prepared draft material summarizing their representative thoughts on the issue for group discussion. The material was then synthesized into a draft report for further review and discussion. A first draft was completed and reviewed in mid-December, 2nd and 3rd drafts in January and a final draft provided to the project consultant, Applied Energy, in March 2003.

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[6] Reference to "energy" in this report broadly includes electric, natural gas, propane, oil, coal, nuclear, or renewables that provide usable power to consumers, usually in the form of heat or electricity. Reference to specific types of energy supply, transmission or distribution will be specifically identified or include the appropriate descriptor.

Transmission and Distribution in Delaware

The transmission and distribution of energy in Delaware, is the responsibility of investor owned utilities, cooperatives, municipals and PJM, Interconnection L.L.C. ("PJM"), the regional transmission organization. Together they manage the transport and flow of energy in various forms, including electricity, gas, oil and renewable fuels such as wood, biomass, photovoltaic and others. Due to the complexity of the topic, a glossary of frequently used terms is provided as Attachment B.

Historically, the State of Delaware has had regulatory authority over vertically integrated energy industry utilities, including supply, transmission and distribution, retail pricing, operations and environmental control. After industry restructuring in 1999, Delaware's role related to electricity supply changed significantly. It became the State's policy to transition to a competitive electric supply market. Nevertheless, important State oversight responsibilities related to electric service reliability, fair pricing practices, market remediation and consumer protection were emphasized as part of the sweeping changes in the restructured supply market. With respect to transmission and distribution the restructuring resulted in a more diverse regulatory and operating environment that included not only state and federal agencies, but also marketplace dynamics. With this diversity of input, it is important for state policy-makers to understand the multiplicity of requirements applicable to the various energy sources and to draft policies that not only provide for open energy markets, but also promotes, or at least does not hinder private and public entities from providing energy to meet consumer needs. Delaware policy-makers need to be aware of the interchangeability of some energy sources and the competitive process by which each industry attempts to grow and develop. State policies must recognize these factors and ensure no undue preference to competing suppliers or transport mechanisms unless such factors are deemed to be in the public interest.

Due to the diversity of regulation some forms of transport are inherently disadvantaged. Under the Federal Natural Gas Act, gas transmission lines have eminent domain authority which permits the lawful taking of property by a gas company, with approval of the Federal Energy Regulatory Commission ("FERC"), for the expansion of gas lines deemed to be for the public convenience and necessity. Conversely, with electric transmission, there is no eminent domain authority granted at the federal or state level. Electric transmission and distribution expansion in Delaware relies on free market negotiations, the willingness of grantors to provide rights-of-way for needed facilities and public rights-of-way. Each type of energy transport has unique requirements that must be considered in any energy policy initiatives.

Electric energy is transported at high voltage levels from generator stations, across a network of towers, poles and wires, to distribution substations. At the substation, the electricity is transformed to a lower voltage for distribution to consumers. In Delaware, electric transmission is primarily dependent on a single investor owned utility (Delmarva Power & Light Company, a subsidiary of Conectiv), with support from facilities owned by the Delaware Electric Cooperative and several municipals. Although the transmission facilities are owned and maintained by the individual utility, the entire electric transmission system in the Mid-Atlantic region (which includes Delaware) is now operated under the authority of

PJM. Energy is bought and sold through markets administered by PJM and transported to consumers under the control of PJM operators pursuant to various agreements executed by utilities, generators, and other market participants. PJM is also responsible for transmission planning according to strict guidelines.

During 1999 the electric industry in Delaware was restructured in an effort to bring energy choice to consumers. Under this restructuring, regulation of transmission and distribution facilities continues under FERC and state authority, while the generation (supply) of electricity was specifically deregulated.

Natural gas and, to some extent propane and heating oil play a key role in meeting Delaware's energy needs. Gas transmission is typically done in large volumes with piping over 24 inches in diameter under high pressure. In lower Delaware, gas transmission uses 8 to 10 inch high-pressure piping. Gas regulator stations are typically used to reduce pressures for distribution to customers. Eastern Shore Natural Gas Company is Delaware's only interstate pipeline transmission company, with a natural gas pipeline running approximately parallel to Route 13 through New Castle, Kent and Sussex counties and ending near Salisbury, MD. Because of the location of this transmission line, natural gas services had been limited to cities and towns lying close to the line, although expansion from Harrington to Milford has recently been completed. Large volume natural gas availability is quite limited in the southern part of Delaware, particularly in the beach area and rural western Sussex County.

Chesapeake Utilities Corporation and Conectiv Power Delivery provide retail gas distribution. Several companies, including Chesapeake Utilities' affiliates provide propane service. Without a major piping system, almost all of the propane business transport is by rail, barge or tank truck to main distribution centers where it is further transported to consumer storage tanks by local delivery fleets. Oil is also available from many different private firms throughout the peninsula and is transported in the same manner as propane.

The majority of electric energy in Delaware is supplied by base load generating stations and mid-merit, quick response units located both on and off the Delmarva Peninsula. Smaller renewable energy sources or distributed generation units make up the balance. Conectiv Power Delivery, a standard offer service ("SOS") company[7], reports that 3.2% of their 2001 energy was provided as renewable energy such as biomass, large-scale photovoltaics, hydroelectric, and windpower.[8] Alternative types of supply also include Distributed Generation ("DG") units that operate with various types of fuel. These units are often interconnected with the electric transmission grid for delivery to the ultimate consumer. However, DG in the form of diesel or gas engine, gas turbine or microturbine is often installed by a consumer to feed its own electrical needs and requires no direct interconnection to a transmission or distribution power grid system. Utilities note that although electric energy alternatives, such as DG, are often purported to be an effective solution to transport or capacity shortages, there are risks of potential adverse impacts on existing transmission systems that must be addressed. Protective equipment is generally needed to ensure that

[7] " Standard Offer Service" refers to the electric supply provided to all retail customers who do not otherwise receive electric supply service from an electric supplier within Delaware's Retail Choice program.
[8] Conectiv Consumer Information Notice (Environmental Information for Maryland Standard Offer Service)

distributed generation facilities and electric transmission or distributions facilities do not adversely affect each other.

With the deregulation of electric generation, the adoption of PJM market rules, and the advent of new merchant energy participants, the energy business has taken a dramatic shift. Where vertically integrated utilities historically provided energy supply with a regulated investment recovery, the decision to expand generation facilities is now based on business decisions of entities who are not rate-regulated and these entities' perceptions of the likelihood of recovering their costs and earning a profit via energy sales. PJM continues to expand market rules, which may affect, among other things, how utilities recover interconnection costs, how economic based investment is promoted, and how merchant generation or transmission companies are compensated. New market rules that are currently being written will set the future course of the energy industry. Given the energy industry as it exists today, the single most important question that remains to be answered is, "What process in Delaware ensures that energy investment is the highest quality and lowest cost investment for the citizens of Delaware?"

Given the complexity of issues, the Work Group examined in some detail the potential impacts of all the critical elements with respect to transmission and distribution capacity. The group elected to review the current system adequacy, load and energy forecasts, the economic impact of the existing system capacities, the availability of alternatives to meet capacity needs, the potential obstacles to capacity expansion such as land use restriction and financial investment recovery, operating constraints, and the potential impact of federal regulation.

CAPACITY ISSUES AND RECOMMENDATIONS

By the end of calendar year 2001, Delmarva Peninsula electric and gas utilities had a total transmission plant investment of approximately $575 million. This represents approximately 2,200 miles of transmission circuits and piping (approximately 1830 miles electric and 370 miles gas.) During the years, 2000 and 2001, these same utilities placed approximately $44 million in new transmission facilities in service and retired $11 million for an average investment growth of 2.9% per year.[9]

Capacity Adequacy

Service levels have continued to meet challenging weather conditions and provide reliable service on the Delmarva Peninsula. The most recent summer peak electric load was 3,758 Megawatts ("MW") on July 29, 2002. A new winter peak of 3,413 MW followed this on January 24, 2003. During the summer of 2002, customer demand for electricity topped previous record demands for over 10 days.

The daily natural gas load on the peninsula has peaked at approximately 260,000 decatherms in 2001.[10] This capacity, although sufficient to meet current load requirements, is unavailable in much of lower Delaware in the significant quantities that would be needed for new heavy industry or gas fired electric generation. This limited availability has significant impact on economic growth and development in Delaware.

While meeting peak summer loads, electric service levels have continued to be reliable. PJM is responsible for maintaining the reliability of the transmission system on the Peninsula. This is accomplished by strict adherence to the North American Electric Reliability Council ("NERC") and Mid-Atlantic Area Council ("MAAC") reliability and operating criteria. These criteria require that the probability of loss of load due to insufficient energy or transport systems should not be greater than one day in 10 years.

Distribution reliability is the responsibility of the local distribution company. Customer service performance is typically measured in number of outages and duration of outages, averaged over all customers. Based on utility reports, the average Delaware customer experienced no more than 1.5 outages per year lasting approximately 1 hour and 15 minutes. While these are only averages, they indicate a reliability level that reflects industry average performance.

Gas system reliability, both at the transmission and distribution level is much higher, approaching 100%. Restoration of gas service after an outage can be an expensive proposition, requiring individual customer visits to ensure gas pilot lights are re-established and equipment is functioning properly. For this reason gas distribution systems are designed to minimize the impact of equipment failure and, unlike electric, is underground and sees relatively few outages due to weather conditions.

[9] FERC Form 1's & 2's
[10] FERC Form 2's

Load Growth

In the most recent US census, Delaware is experiencing some of the highest growth rates in the nation. From 1991 through 2000, the population of the United States in total grew 13.1 %. During this same time period, the Delmarva Peninsula population grew by 16.9%, the State of Delaware population by 18.4%, and Sussex County, Delaware population by 38.3%.[11]. These high population growth rates have placed increased demand on energy transport mechanisms required to meet related energy needs. Conectiv Power Delivery's 2001 forecast load growth rates for Delaware vary from 0% to approximately 10.2 % depending on the particular planning area, averaging around 3%.[12]

Electric load growth on the Peninsula continues to grow in a similar manner. One energy supply forecast anticipates an 18% peak load growth by 2010, for a 2% average annual peak growth rate. The growth of Delaware electric energy usage, including estimated losses, is forecast for the same period at 18.5%, a 2.1% average annual growth rate.[13] Another peak load forecast for Kent and Sussex counties predicts a 5.6% winter growth rate, with total energy requirements growing at 5.4% annually.[14] Load growths such as these create a challenging environment in which to maintain reliable, low cost electric service for Delaware consumers.

RECOMMENDATION #1 – (CRITICAL)

Delaware should maintain, and enhance where possible, its effective energy management process, ensuring continued reliable, cost-effective electric/gas supply and transmission infrastructure, and continuing to meet anticipated consumer load growth requirements.

The supply and delivery of energy to consumers is critical for the continued economic development and growth of Delaware. Where supply is not available, transmission capacity can help to import the energy needed and vice versa. An effective energy policy should provide for a balance between supply and transmission capacity.

The reliability and integrity of the electric and gas supply in Delaware is currently dependent on the PJM planning process, their expansion plan mandates for reliability, and the marketplace decisions of unregulated electric generators, gas suppliers, and merchant energy transmission utilities.

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[11] 2000 U.S. Census Report
[12] Conectiv Power Delivery T&D 5 Year Planning Study, dated December 2001 and January 2002
[13] Applied Energy Group, Inc. "Delaware Non-Transportation Energy Supply Forecasts", dated November 2002
[14] Delaware Electric Cooperative, 2002 Power Requirements Study, 2002 – 2016, Completed in November 2002

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Actions currently in process:

1. PJM planning process requires the transmission systems to meet NERC, MAAC and PJM reliability requirements.

2. PSC staff is proposing electric reliability regulations to comply with the restructuring legislation reliability mandate. The initiative to establish these regulations is estimated to cost $100,000, billable to electric utilities.

3. PSC staff is proposing revised reliability legislation related to potential penalty assessments.

4. Marketplace rules, under which third parties or merchant companies may provide transmission or supply, are in process of being filed by PJM.

5. Each utility independently plans to ensure that it is capable of meeting load requirements.

Recommended non-legislative actions

None

Recommended legislative proposals

None

> Current Delaware law (Delaware Code, Title 26, §1001 et.seq, the Electric Utility Restructuring Act of 1999) provides regulatory authority to the PSC to maintain reliability of electric service and authorizes the Commission to address supply issues relating to market power remediation, standard offer service, electric supplier certification, and consumer protection and education. The Commission's regulatory authority over transmission and distribution under the Act, remains largely unchanged.

Areas for further evaluation or research

1. The PSC should consider a special taskforce to review the potential for a financial incentive program designed to encourage the expansion of generation and electric/gas transmission facilities consistent with Delaware energy needs.

2. The recent U.S. Census indicates a Delaware growth rate higher than the national average. Further research is needed to translate this level of population growth to energy consumption and the facilities needed to meet energy demands. Although PJM and utilities forecast load growth based on historical, weather normalized, peak loads, a process which provides for future growth rate factors will be critical to meeting energy system needs. Consideration should be given to establishing a special taskforce to review the utility planning process to ensure adequate recognition of population growth and related energy loads.

REGIONAL PLANNING/POLICY ISSUES AND RECOMMENDATIONS

Electric and gas transmission systems have been expanded historically to meet peak customer loads. For gas transmission this means adequate pipeline capacity and storage to meet current peak residential and business demands. Investment in future capacity is dependent on the needs of the customers and not typically made until there are assurances of adequate revenue recovery from the customers to be served. In similar fashion, the electric system is designed to meet peak electric loads without risking a loss of service. This approach has required that just enough investment be made to maintain service levels while meeting system operating and maintenance needs.

To assess the effectiveness of the current electric and gas transmission and distribution system planning and its impacts in the region, it is critical to understand:

- the regional nature of energy transmission,
- the technical and financial characteristics of the system, and
- the implications of new federal/regional/PJM policies.

Regional Nature of Energy

Electrical energy is a special commodity that must be produced as it is consumed. There is limited storage ability, except where it is stored in an alternative form, such as pumped hydro, or air/gas pressure caverns (neither of which are available in Delaware.) As electricity is consumed, generator output varies to meet the constantly moving demand. Electricity is real-time dispatch coupled with real-time use.

Electrical energy also flows according to the laws of physics. Electrons put on the transmission grid by a generator take the path of least resistance, without regard to city, county or state borders. Hence it is essential that management of this resource be viewed from a regional perspective. The majority of electric transmission in the United States is alternating current (AC) transmission with limited ability to control power flows, except for generation dispatch. The only real controls on energy flow are direct current (DC) system ties, that can often be controlled to meet specific energy flow needs; however, Delaware has no DC transmission.

Electrical energy is a commodity that, at times, is interchangeable with other forms of energy. A home or industry needing a heating or cooling source may have multiple fuel options including electricity, natural gas, oil, or coal. Conversely, motors, control circuits and most household appliances need electrical energy to operate. When examining energy needs and planning capacity requirements, it is important to keep this interchangeability in mind as it provides multiple options to ensure adequate energy supplies. The availability of natural gas can sometimes offset the need for additional electric transmission capacity and vice-versa. A valid comparison of various energy alternatives can often provide the most efficient, low cost solutions, all other factors being equal. Generation in place of transmission, natural gas in place of electric, coal in place of natural gas as a generating fuel are just some of the possibilities a thorough regional planning process should consider.

However, in the current competitive environment with limited ability to influence the unregulated market process, decisions are based on the business community's assessment of investment risk.

When one examines the electric transmission grid on the peninsula, it is obvious that electricity can flow from generators throughout the Delaware, Maryland and Virginia transmission systems. Energy flowing down Delaware's major 230KV lines provides service to Maryland and Virginia areas and conversely, energy flowing from Maryland transmission circuits provides service to lower Delaware areas. A quality energy policy recognizes this regional nature of electric energy and provides a process by which states are able to select the right energy solutions without regard for political boundary.

Technical and Financial Characteristics

The electric transmission system on the Delmarva Peninsula has traditionally been planned, constructed and operated by Conectiv to meet NERC, MAAC, PJM, FERC Form 715 and local utility reliability criteria. Delaware Electric Cooperative (DEC) and some municipal utilities have transmission facilities that are subject to similar planning standards, but their transmissions systems are less extensive. Recently, PJM has assumed a larger role in the planning and operational process. The high voltage bulk system is planned such that the probability of loss of load due to insufficient tie capability is not greater than one day in 10 years. The transmission system capability is typically measured in Megawatts ("MW") or MegaVoltAmperes ("MVA") and is based principally on the transmission voltage and current carrying capacity of the conductor. System studies ensure that the electric transmission system has adequate capacity to meet normal/emergency needs.[15]

The natural gas transmission system is similarly designed to meet peak winter load, exclusive of interruptible demand. System capacity is calculated in an analogous fashion to electric. Capacity is dependent on the pipe size and the transport pressure maintained in the transmission installation. Transmission capacity is typically measured in million cubic feet per day (MMcf/d), and the limits on capacity include pipe size, pressure handling capabilities, and the number, size, and locations of compressor stations.

Energy prices have historically tended to reflect the technical needs of the system. Prior to restructuring, this provided for a regulated return on mandated infrastructure improvements. This approach usually resulted in high quality service and reasonable energy costs, both of which were readily accepted by the general public. Both wholesale and retail customers have

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[15] To ensure adequate capacity of the high voltage system, studies are conducted to measure available transmission capability (ATC), import capability, deliverability, capacity transfer levels under contingent conditions, and simultaneous feasibility/dynamic analysis. Contingent transfer studies are performed by PJM to ensure sufficient capacity exists to maintain the same 1 day in 10 years loss of load probability. This is typically referred to as a comparison of the Capacity Emergency Transfer Objective (CETO) to the Capacity Emergency Transfer Limit (CETL) for the sub area. The CETO is the import capacity needed to keep a sub area at no more than a 1 day in 10-year loss of load probability. The CETL is the amount of load that can be reliably transferred to a sub area from the remainder of PJM's territory in the event of a generation deficiency. A net positive margin meets the standard. Available Transmission Capability studies are typically performed on requests for transmission access and involve an analysis of power flows and available capability from source to sink.

expressed a desire for reliable, environmentally friendly, low cost energy for their homes and businesses. When both costs and service level were regulated together, this responsibility fell to utilities with regulatory oversight. Now, except for temporary retail rate freezes, cost responsibility for electricity supply is dependent on marketplace energy bids (via independent market participants), merchant business investment and the regulation of EDCs and SOS suppliers. Additionally, services levels, while still regulated in part,[16] can vary significantly depending on a utility level of investment and commitment to quality service.

The regulated capacity investment recovery for both gas and electric transmission is quite similar. Utilities, adding facilities to keep pace with demand and reliability requirements, must typically file a rate case application with FERC and secure approval to include new facility investment in a revised rate structure. Upon rate approval, customer charges provide a revenue stream for the life of the asset. Although seemingly a simple process, a utility faces several financial business risks in this process. There is always the possibility that the investment is determined to be unnecessary and therefore disallowed. There is the possibility that an approved rate of return could be lowered because of reduced equity costs or an over-earning situation. And lastly, there is the possibility that the anticipated revenue from the extension is either deferred or fails to materialize, at which time the costs must be borne by the present ratepayer, without significant benefit. However, these risks are not new to public utilities, as the regulatory process has always included these to some degree. In the current environment, Delaware and many other states have put in place rate caps during the transition to a competitive retail market. These rate caps impose added risk to transmission owning utilities in recovery of the cost of new construction in general. Some wholesale customers believe that rate caps go even further by providing a disincentive for transmission projects needed for economic improvements.

To avoid these risks, many gas and electric utilities that add infrastructure to meet new load, often charge the new load customer for some portion of the investment, ranging from a small percentage to total cost. Generally, however, this direct assignment of costs is used only for smaller investment where the benefits are clearly enjoyed by a limited number of customers. Specific assignment ensures recovery of investment costs up front and places the cost of investment directly on the customers who need the service. However, gas and electric improvements that are broad based and affect regional areas, are generally made for reliability purposes and recovered via rate changes affecting either all customers or at least all customers in a given region.

New Federal/Regional Policies

The electric, gas, oil and coal industries continue to evolve. Where there was once strict regulation, there are now market forces that are intended to provide the appropriate direction for business investment. The FERC has recently come out with proposed rule makings on Generator Interconnection requirements, Small Generator Interconnection requirements and Standard Market Design ("SMD") requirements. Each of these potential rule makings has the possibility to impact not only the level of transmission capacity resources available for

[16] While the Delaware Public Service Commission continues to regulate a load serving entity for service reliability, the Commission no longer regulates entities that generate electricity. Therefore some aspects of service provided by such an entity are dictated only by market conditions.

Delaware consumers, but also the price at which energy is available from the transmission grid. Add to that the various state regulations on service quality and retail pricing along with the advent of merchant transmission projects, and the future of transmission capacity becomes quite cloudy.

There are several issues within recent FERC Notices Of Proposed Rule Making ("NOPRs") that have a potential impact on Delaware and the energy policies that may be developed. Each of the NOPRs put forth proposals for states to have input on transmission issues; however, much of what FERC has proposed is based on the current PJM approach.

Multi-State Entities ("MSEs") and Regional State Advisory Committees ("RSACs")

FERC has advocated the initiation of either RSACs that reflect the makeup of the planned Regional Transmission Organization ("RTO") areas and/or MSEs to address regional issues. RSACs would provide advice to FERC on regional issues, while MSEs would provide for regional planning and issue resolution. A serious concern, even if either approach is workable, is that Delaware's voice could potentially be lost among the many participants and that a group covering such a large area is unnecessary to adequately represent Delmarva Peninsula issues.

Commitment to Marketplace Dynamics

Although not specifically stated, the SMD by its very nature is supportive of market place dynamics. Generators, Independent Transmission Companies ("ITCs"), and regulated utilities (in the absence of regulation) will tend to make business decisions that are the most cost-effective, highest return, and in the best interest of their shareholders. A properly written set of market rules will ensure that the best economic decisions are made for the transmission system. However, to ensure a reliable, economic transmission system and adequate energy reserves, FERC proposes a resource adequacy requirement that would be managed by the RTO or Independent Transmission Organization ("ITO"), and be established based on regional need. The commitment to existing market place dynamics and the move to a more flexible resource adequacy requirement may not always provide the best solutions for Delaware consumers; however, the resolution of the load pocket issues that have been raised with respect to the SMD NOPR would have an immediate beneficial impact on Delaware.

Postage Stamp versus License Plate Rates

The most recent transmission rate structure proposal suggests a movement toward postage stamp rates, a single rate for use throughout the RTO. Although this approach eliminates rate pancaking, it does require a re-allocation of revenues to the various TOs and may result in cost shifts. Whatever rate structure FERC finally approves, it needs to recognize the costs associated with energy flow across systems as this may have a significant effect on Delaware ratepayers.

Supply Planning and Demand Response

The FERC SMD NOPR relegates supply planning and demand response to the various state and regional planning entities. Delaware's 1999 Restructuring Act established no state requirements for either supply planning or demand response programs and leaves the implementation of these efforts to PJM and the deregulated generation marketplace. The Delaware PSC monitors PJM's efforts and participates in policy development on these important issues.

Generator Interconnection Standards

FERC's NOPR on Generator Interconnection Standards provides a basic, consistent structure in the handling of generator interconnection requests and helps to streamline the process, limiting barriers that may impede the development of new generation projects.

PJM and Merchant Transmission

Merchant transmission companies have recently begun to look for investment opportunities in areas where marketplace rules have been established and they see potential for high return on investment. PJM has recently been drafting tariff rules under which merchant transmission companies in Delaware would be eligible for a return on investment. The merchant transmission companies, utilities and other stakeholders while participating in regional planning meetings have assisted in developing these rules. How the merchant return on investment compares to a regulated return on a similar investment will likely determine the future of transmission system development. If merchant returns are significant under the new rules, it is likely that many of the main high voltage facilities may be merchant projects and the lower voltage lines will likely remain as regulated investment. Market rules will drive the investment that companies see as profitable. Whether such investment is an economic solution for Delaware is only of consequence to the ratepayer if the facility is actively used and useful, in which case the energy ratepayer will ultimately pay for their share of usage.

Delaware law appears to classify merchant transmission as a "public utility", which would require business licensing and certification by the Public Service Commission.[17] While this does not have a direct impact on transmission expansion it does provide Delaware with the opportunity to maintain PSC awareness of merchant facilities and to ensure such entities meet public utility service level requirements.

[17] 26 Del. C. Chapter 1

RECOMMENDATION #2 – (IMPORTANT)

Delaware should help facilitate the establishment of a Multi-State Energy Commission that in coordination with federal, state and regional agencies, utilities and energy consumers, identifies and, where appropriate, mandates and finances the infrastructure requirements needed to ensure the long-term sustainability of cost competitive energy supply, transport and delivery on the Delmarva Peninsula.

Today's energy transmission system, based on meeting reliability parameters, has been very effective at delivering energy to consumers. However, during periods of high load or system constraint, energy prices have risen. In the electric industry this has been because of off-cost generation needed to maintain the operating integrity of the system and alleged in some instances to be based on generator bid practices. In the gas industry it has been caused by the decreased availability of fuel supplies and the need to pay higher prices for system delivery during peak load periods. The Delmarva Peninsula and its wholesale customers have experienced these energy prices and with the expiration of Delaware's retail electric rate caps in 2005/2006, there is a possibility of significant consumer price increases. To provide for a competitive economic energy future in Delaware, it will be necessary to minimize electric transport constraints and to establish a broader geographic gas infrastructure to meet a diversity of consumer needs.

Historically, each utility has addressed system limitations in their own planning and decision making process. However, those decisions were made only with respect to their particular energy product or service. Within the electric utility industry, and prior to restructuring, there was an Integrated Resource Planning ("IRP") process that assured electric consumers of the most economic solution to meet their energy needs, whether it was generation or transmission. With the restructuring of utilities, much of that planning process has fallen by default to the decisions of marketplace participants. PJM, as the RTO, monitors the availability of electric supply and ensures that adequate facilities are in place to meet industry requirements.

Delaware, Maryland and Virginia are uniquely positioned to address these energy cost and adequacy issues. The Peninsula states not only understand and have experienced the implications of federal and regional energy policy, but they are able to provide an environment in which remediation proposals can be effectively evaluated. As a relatively small state, Delaware provides an opportunity to work and develop new policy approaches that ensure continued reliable service at cost-effective rates.

The establishment of a Multi-State Commission, as part of Delaware's energy policy, provides an effective planning and management mechanism that is critical to developing and maintaining cost-effective energy solutions for Delaware and the Peninsula as a whole. The mechanism should include a process that not only formulates the need for additional capacity, but also the specific types of capacity that are both reliable and economically effective, under existing market structures. The Multi-State Commission must have a multi-state commitment, the necessary resources, the legislative authority to conduct regional studies, and the authority to mandate or stimulate appropriate energy investment.

Although electric service is essential to almost all customers, there are tradeoffs where energy sources are sometimes interchangeable. In many instances, one source of energy can mitigate supply or transport problems in another energy system. The extension of gas mains to fuel a generating station may likely eliminate an electric transmission enhancement. It is essential that Delaware, Maryland and Virginia have the ability to select the "right" energy solution for the Peninsula, keeping in mind that Delaware may need to compromise its energy requirements to ensure the best solution for the Peninsula. Where energy solutions cut across broad customer bases, it is important that solutions be paid for by all who benefit from the investment. A multi-state energy planning and management process, that is able to integrate various energy needs so that the most economic and environmentally acceptable solutions are developed (independent of energy type or method of supply) will ensure a competitive energy future on the Peninsula.

Actions in process

1. PJM is reviewing various approaches to its planning process, designed to meet FERC requirements for incorporating economic planning in its overall process.[18] They are coordinating their activities closely with the various state agencies and stakeholder utilities.

2. The Delaware Public Service Commission continues to coordinate with the National Association of Regulatory Utility Commissioners ("NARUC"), the Mid-Atlantic Conference of Regulatory Utilities Commissioners ("MACRUC") and PJM on energy planning and management issues. Recent proposed federal rules and current marketplace impacts surrounding the cost of electric congestion have prompted coordinated multi-state utility commission discussions.

3. Natural gas transmission and distribution provides energy to many Peninsula customers. System expansion initiatives are limited to specific customer requests or select market opportunities.

Recommended non-legislative actions

1. Delaware should continue to coordinate with Maryland, Virginia, PJM, utilities and other interested parties on all energy planning issues. Resources are currently available for this process and the estimated costs are limited to communication and travel as necessary.

Recommended legislative proposals

1. Delaware should help facilitate the initiation of a joint Multi-State Energy Commission that, in coordination with federal, state and regional energy agencies,

[18] FERC Docket No RT01-2-000, Order dated July 12, 2001, Approving provisional RTO status for PJM.

maintains energy sufficiency by evaluating and implementing the most economic and reliable energy supply and transport capacity additions.

a. Draft a joint state resolution to establish a Multi-State Energy Commission that:

- identifies a regional organizational structure capable of representing diverse energy interests, conducting energy capacity alternative studies, and implementing approved enhancements,
- involves all interested stakeholder representatives,
- identifies energy supply needs,
- identifies both reliability and economic transmission needs,
- identifies critical supply or transport issues,
- provides investment incentives and/or assurances of investment recovery,
- monitors the status of the regional energy system,
- has sufficient resources to manage energy investment,
- sets forth the authority and responsibility of the commission, consistent with multi-state executive/legislative concurrence, and
- identifies the work process and resources needed to ensure energy sufficiency across the region.

b. Establish a joint state mechanism to provide for necessary commission funding and staffing requirements.
c. Secure joint state membership, concept approval, and general agreement to create a Multi-State Energy Commission.

A substantial portion of the estimated cost for establishing a Multi-State Energy Commission is based on the human resources and facilities needed to support such a commission. Within Delaware, there are currently multiple agencies that have energy interests. The availability of resources from these agencies could help to offset the estimated costs of establishing a Multi-State Energy Commission. However, without such offset, the minimum total cost is estimated at $1.2 million annually.[19] Delaware's portion could be approximately one-third of this amount. Issues to be addressed include the level of control that Delaware would have at a regional level, the fair allocation of costs of operation, and the need to ensure that all stakeholders are fairly represented at the regional level

2. Delaware should establish legislation in support of the joint state resolution, authorizing the establishment of the Energy Commission.

[19] Cost estimate is based on a small five person full-time staff and part-time Commission of nine members. It includes salary, benefits, travel and administrative costs estimated at $75,000 per full time person, $30,000 per part time person and $600,000 in annual energy planning program costs and related technology software costs. The Multi-State Energy Commission is assumed to include the states of Delaware, Maryland and Virginia.

Areas for further evaluation or research

The potential to address energy issues on a multi-state, coordinated response approach is a viable option; however, current agencies have limited authority with respect to some individual industries. As an example, there is no authority at the state level to mandate gas transmission expansion even if it were the most economically effective approach. The potential of using incentives for such investment is a possibility, but sources for funding such incentives are limited. It may be appropriate to investigate additional alternative ways to identify infrastructure needs and mechanisms to stimulate investment.

DELAWARE PLANNING/CONGESTION ISSUES AND RECOMMENDATIONS

Although transmission and distribution are regional issues, there are many concerns that can also be addressed at the state level. There are unique state issues such as high load growth, transmission capacity constraints, economic development and environmental concerns that could benefit from a more coordinated state approach. To understand how the state can impact these issues, it is important to examine:

- the underlying investment planning process,
- the economic impacts of constrained or congested operations, and
- the related environmental concerns.

Capacity Planning

The basis of any energy capacity plan is the load to be served. Utilities traditionally measure system load flows and forecast load growth based on many different inputs. Anticipated weather conditions, economic conditions, known new customers, population growth trends and historical usage are all combined to establish the forecast energy capacity need. Annual population growth rates of around 1.0% - 1.5% are typical state averages, but the lower Delaware beach area, has experienced an annual population growth rate as high as 3.8%[20]. Electrical energy load growth in the area is forecast as high as 5.4%.[21] Where capacity shortfalls are identified, utilities typically plan for system configuration changes or new investment as appropriate.

Energy usage growth is decidedly weather sensitive and planning processes must consider a weather normalization approach. Most utilities assume a 50/50 weather normalization, but this can vary, depending on the criticality of the facilities being planned. A 50/50 normalization assumes that peak summer temperatures for the planning year will be at the historical norm. Some utilities use a 90/10 weather normalization ratio, which would use a peak summer temperature that reflects a level below which 90% of observed peak temperatures will fall. Some utilities apply different weather normalization methods to different sectors of their transmission and distribution system. PJM uses the 50/50 approach for supply related studies and for general transmission planning purposes. PJM applies a 5% adder to the 50/50 approach to develop a proxy for a 90/10 forecast that is used in the Capacity Emergency Transfer Objective (“CETO”)/Capacity Emergency Transfer Limit (“CETL”) system analysis examining the system interconnection transfer capabilities.[22]

Planning for lower voltage transmission and distribution capacity is conducted by the individual utilities responsible for service, subject to established local reliability guidelines. Based on peninsula wide load forecasts, the Delmarva system is planned assuming that Peninsula generation is available (unless scheduled for maintenance which is generally not

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[20] US 2000 Census
[21] Delaware Electric Cooperative, 2002 Power Requirements Study, 2002 – 2016, Completed in November 2002
[22] PJM Operations Manual

permitted by PJM during expected peak periods) and that the transmission interconnections with other utilities will be available to supplement supply so as to meet peak load requirements, adjusted for diversity, weather and load factors. Typical planning standards involve meeting a set loss of load probability with contingency backups designed to achieve established performance parameters.

Plans to meet forecast electric load requirements often involves a mix of both generation and transmission facilities. While an expansion of either facility can provide the needed energy, each solution can have varying costs and impacts on the transmission system. PJM routinely conducts feasibility studies for new generators wishing to connect with the transmission system or for new/upgraded transmission as part of the transmission planning and expansion function. A new generator is expected to pay for the cost of the direct interconnection if the project is deemed feasible by the PJM study. A new generator can also be expected to pay for system reliability improvements, provided by the transmission owner, when such improvements are required as part of the interconnection process. When a regulated transmission owner is required to make system improvements to meet mandated reliability requirements, independent of any generation project, the owner is expected to pay for the necessary investment with the potential to recover the investment through tariff rates. Currently, unregulated merchant transmission companies, desiring to provide system enhancements, must meet the same feasibility study requirements as regulated companies, must pay for the feasibility study and the system investment, and receives compensation based on the use of the system facility, as approved in the PJM Operating tariff.

With respect to natural gas and other energy transport mechanisms, feasibility studies are typically demand based and completed only as new load revenues can be assigned to the investment. In addition, a significant amount of oil and gas interruptible load provides for increased flexibility in meeting supply requirements. There is no regional entity that mandates transmission investment across a broad geographic area to meet established reliability or economic criteria, outside of the Department of Transportation safety mandates. Each company is free to establish its own capacity standards and to maintain its system. Rail, barge and truck transport of energy commodities are also regulated by the Department of Transportation primarily for safety purposes. Actual transport capacity is limited only to the level of investment that private carriers are willing to make in additional labor and equipment.

An important aspect of the planning process is also the time horizon associated with the anticipated installation of new investment. Utilities have historically planned capacity investments to be in-service in time to meet forecast load growth. Under peak load conditions, this sometimes resulted in limited transport reserve margin and potential exposure to system congestion. The time frame associated with plans for added investment depends on the level of transmission capacity reserve margin that utilities desire to maintain (risk of loss of load, or economic impact) and the cost comparison of capacity alternatives.

The Delaware PSC plays a key role in the project planning process by reviewing utilities' five-year plans and ultimately in the investment recovery process via the ratemaking proceeding. Utility investment that either overbuilds system requirements or falls short of needed reliability can be subject to financial consequences and ultimately impacts business decisions.

Economic Impacts

In today's restructured environment, transmission capacity can have both service level and economic impacts throughout the entire region. Both reliability capacity additions and economic capacity additions need to have appropriate planning. FERC recognized this need in its July 12, 2001 Order, Docket No. RT01-2-000, approving PJM's provisional RTO status. FERC identified several modifications that needed to be incorporated in PJM's Operating Tariff, including the need for the planning process to focus on identifying projects that expand trading opportunities, better integrate the grid, and alleviate congestion that may enhance generator market power."[23]

Economic impacts began to occur in Delaware in 1999 with the implementation of Locational Marginal Pricing (LMP), the transfer of lower voltage transmission facility control to the regional operator, and the need to operate under strict NERC/MAAC guidelines. These changes often resulted in the need to dispatch higher cost generation in the DPL pricing zone to ensure line or equipment capacity ratings were not exceeded, thereby contributing to significant energy cost increases (congestion pricing) during periods of transmission constraint. These costs have usually been paid for by all Load Serving Entities ("LSEs") that have energy requirements within the constrained area due to current retail rate caps. The Delaware Public Service Commission considers the economic impact of these congestion costs a very serious issue that has the potential of adversely affecting the economic well being of the state by creating entry barriers for new, competitive energy suppliers and industry in Delaware.

PJM's electric energy pricing mechanism (LMP) prices all MWs consumed in the DPL price zone at the cost of the next incremental generation bid price. Although providing the appropriate market investment signals to potential energy investors, other obstacles such as fuel shortages, fuel costs, environmental concerns, and business risk on the peninsula have prevented significant levels of new investment outside of the regulated industry. In the view of some utilities this pricing mechanism, as currently approved by FERC, is unfair and needs to be modified to reflect the true cost of generation in place of the next incremental MW cost.

Faced with increased supply costs from 1999 through 2001, LSEs have been looking for ways to reduce or eliminate periods of constrained operations. In many cases, the constraint could be eliminated or reduced by increasing the capacity of the constrained facility, however that requires additional system investment that is not necessarily required for reliability purposes. PJM has been examining potential mechanisms to mandate system enhancements to mitigate economic costs. They have started to identify the facilities that have contributed to these high costs and to post related information for potential new merchant projects.

It is generally agreed that there is a need for transmission system enhancements or additional on-Peninsula generation to support the reliability of the system and to help to minimize the

[23] FERC Order under Docket RT01-2-000, dated July 12, 2001

cost of energy. The difficulty in meeting the "minimal cost of energy need" is establishing the economic criteria under which an economic system enhancement would be required, the process by which both regulated utilities and unregulated merchant companies would have fair opportunity to meet the need, and the mechanism by which PJM would be compensated for the feasibility studies. Most participants agree that both economic and reliability enhancements need to be implemented to ensure a reasonably priced, reliable system. However, since current capacity constraints may become future reliability concerns, as load continues to grow, it is difficult to separate economic and reliability enhancements except from a timing perspective or the driving factors of the marketplace. It is also important to consider the cost benefit of long-term solutions versus short-term solutions to these constraints.

Hours & Projected Costs

The system, as currently maintained and with existing generation resources, provides reliable electrical capacity to meet peninsula loads. However, the cost of such energy, particularly during high load conditions or with system load constraints, has exceeded nominal market prices approximately 10-15% of the time during 2000 and 2001.[24] Over the past three-year period ending August 2002, Delmarva's electric transmission customers have paid over $130 million in congestion charges (6,762 hours of constraint) that resulted from the dispatch of off-cost generation (see Attachment C).[25] Proportionally, a larger portion of these hours occurred prior to 2002, when congestion hours were below the 4-year average by approximately 20% (see Attachment D).[26] Although Delaware consumers have been protected from these costs (due to retail rate caps through 2005/2006,) utilities have had to absorb these costs since August 1999. Congestion has been caused by a variety of factors, with the predominant ones being new generator and transmission line cut-in testing, maintenance outages, forced generator and equipment outages and high loads. In short, the transmission grid on the Delmarva Peninsula, because of the geography, the radial nature of the grid, limited system redundancy, load growth, and the change to LMP pricing, has been particularly vulnerable to energy flow constraints and the related economic consequences.

While a reduction of congestion cost to more reasonable levels is critical, utilities have been reluctant historically to invest in new facilities solely to reduce congestion or to include the economic impacts of congestion in their planning process. Utilities cite an inability to accurately forecast congestion, a risk of not recovering the investment in FERC proceedings, and failure of the cost structure to equitably allocate such costs across those customers receiving the benefit.

Hours of constrained operation in 2002 are down significantly when compared to the previous year. January through November hours are 1,025 hours in 2002 compared to 3,168 hours in 2001 for a 68% reduction. Between 1999 and 2002, Conectiv, NRG Energy, Commonwealth Chesapeake Company and municipalities added a total of 1000 MW of new generation to the Peninsula. This represents an increase of 35% relative to

[24] PJM Delmarva Peninsula Congestion Study (Attachment C)
[25] PJM Delmarva Peninsula Congestion Study (Attachment C)
[26] PJM Delmarva Peninsula Congestion Presentation (Attachment D)

pre-1999 capacity, and 20% of all the capacity added throughout the entire PJM region over the same period.[27]

Although this reduction of constrained hours has been significant, it does not necessarily signify that congestion on the Peninsula has been resolved or the cost of congestion has been eliminated. The congestion cost on the Peninsula through August 2002 was estimated at $21.38 million.[28] Continued load growth coupled with a lack of system robustness may very well contribute to future increases in congestion hours. It will be critical to monitor load growth, construction testing and maintenance outages to effectively manage congestion.

In early, 2002, Conectiv (the principal transmission provider) completed its merger with PEPCO. As part of that merger settlement, Conectiv agreed to work toward reducing congestion, (exclusive of generator or transmission forced outages or new construction), by gradually reducing the hours of congestion to 600 hours by 2005. Conectiv also agreed that when it failed to meet targeted annual reduction goals, it would perform economic analysis on potential mitigation projects and construct those projects that met benefit tests[29]. Hours of congestion have continued to decline through 2002. Conectiv has met its 2002 merger settlement target of no more than 1,000 qualified hours[30] and has continued to work at reducing potential congestion concerns. Nevertheless, congestion continues to be a moving target. With the dramatic growth rates previously discussed total congestion hours may well result in future constrained hour increases.

While local distribution companies have continued to provide reliable electric service on the Peninsula, the cost of such service, due to congestion, has been higher than those costs experienced in other energy markets in PJM. In 2000 and 2001, a substantial amount of this congestion cost was due to new transmission construction and generator interconnection testing on the peninsula. The costs of congestion attributable to peninsula constraints has fallen significantly in 2002 as compared to 2001 but are similar to 2000 based on PJM's estimates. Some congestion impacts experienced on the peninsula are regional in nature, (i.e., constraints in Pennsylvania, limiting energy flows from west to east, create higher prices throughout the PJM East region, including the Peninsula). However, much of the historical congestion cost has occurred in the Delaware and Maryland area. A regional approach, complimented by improved state coordination can help to minimize high energy costs and develop wholesale markets needed for Delaware consumers to gain the advantages of energy competition. System investment for both reliability and economic benefit must be incorporated in both a regional and state planning process and in the various Delmarva Peninsula utilities local planning requirements.

Even with congestion costs reduced in 2002, there is concern that such reduction may not be representative of a typical year and may, in fact, be a short-term result. With

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[27] Source: Conectiv Power Delivery Supplementary Material
[28] PJM Delmarva Peninsula Congestion Study (Attachment C)
[29] Conectiv/PEPCO Merger Settlement
[30] Per the Conectiv/PEPCO Merger Settlement, qualified hours exclude generation or transmission force outages and generation or transmission construction.

congestion being primarily caused by the testing and cut-in of new facilities, forced equipment outages and planned maintenance outages, it is inevitable that future system enhancements and maintenance of the system will result in some degree of congestion. The group feels that there are ways to manage the level of congestion hours such as managing and planning effective maintenance programs, coordinating and shortening maintenance outages and managing the scheduling of new facility testing and cut-ins.

PJM Summary Evaluation of Delmarva Peninsula Congestion

PJM has recently completed a preliminary review of congestion on the Delmarva Peninsula. Their study examined all occasions of congestion from 1999 through August 2002 and described many of the difficulties in trying to calculate the economic impact. PJM concluded that the $130 million cost, although on the high end of an estimate, is indicative of the level of economic impact that has been experienced by wholesale transmission customers.[31]

In reviewing some of the more significant congestion events during that period, PJM has demonstrated in recent meetings the difficulty of reaching an easy solution to system constraints. As an example, the replacement of a limiting transformer that caused 200 hours of congestion may only resolve a small portion (5 or 10 hours) of the limitation as there could exist another limiting facility such as a line or bus directly beneath the transformer limit that might also need upgrading. And then beyond that, there could be a second line, bus or breaker that needs to be upgraded to avoid constrained operations. Even if one could identify all the potential limiting equipment and upgrade them there is the possibility that such configuration change might merely move the congestion hours to another circuit or piece of equipment on the transmission grid.

Delaware Economic Impact

Delaware consumers spend over $1.0 billion on energy and energy related products annually.[32] The delivery of this energy is heavily dependent on the availability of both gas and electric transmission capacity and impacts Delaware's economy, not only from an energy service level, but also from an economic development perspective. There are four (4) key energy variables that need to be considered.

1. Energy Cost - While energy has continued to be available in reliable quantities, it has experienced some periods of high cost due to congestion. Upon expiration of current price caps, there is a real risk that the cost of energy will be significantly higher for the average consumer unless the lower levels of congestion experienced in 2002 can be sustained and improved upon.

2. Load Growth - High growth rates will invariably be associated with a need for more energy and energy transport capacity to meet customer needs. A robust

[31] PJM Delmarva Congestion Study and Presentation (Attachment C & D)
[32] Gross Revenues FERC Form 1&2's

transmission system that not only meets today's needs, but also provides for future capacity will be critical to meet this energy need in a cost-effective manner.

3. Market Based Decision Process – Energy capacity investment decisions (both generation and transmission), beyond those mandated for reliability, are being made by individual businesses seeking to maximize their economic benefit. With the restructuring of the electric industry, Delaware consumers will have to accept a market based decision process as the foundation of future investment. However, market solutions do not necessarily guarantee the most cost-effective approach.

4. Economic Development – Economic siting for many industries is tied directly to energy cost, service and availability. The lack of a robust, low cost energy system, coupled with limited gas supplies, creates a significant barrier for many industries looking for new manufacturing sites. Due to a relative lack of base load generation in the southern portion of the Peninsula relative to the North, the impact of congestion costs tend to be higher in the South. This could drive new prospective industrial customers to locate in the North rather than the South.

Environmental Concerns

Resolution of transmission planning and congestion issues can have a significant impact on the environment. Although the addition of electric generation in the area may help to reduce transmission congestion and the related economic impact, it is not without environmental cost. Conversely, the addition or upgrade of transmission circuits, many of which cross environmentally sensitive areas, also impact Delaware's environment. Extensions or upgrades of gas transmission systems, which require burial of large piping runs, can also have significant impact.

The recent development of renewable energy resources ("green energy") can offer a more environmentally acceptable solution where generation could be the best solution. However, as a marketplace alternative, with a somewhat higher price tag, it has limited demand in Delaware. Other states, such as New Jersey, have established Renewable Portfolio Standards ("RPS") that mandate a certain percentage of energy from "green" sources. This approach, while good for the environment, places a higher price tag on energy in the Delaware and may establish a barrier to economic development.

It is essential that energy policy-makers, economic development experts and environmental agencies coordinate closely on energy solutions. Without close coordination, Delaware may not be optimizing the solution that best meets all of Delaware's energy objectives.

RECOMMENDATION #3 – (CRITICAL)

Delaware should establish a State Energy Coordination Stakeholder Group that monitors Delaware's energy transport system, drafts and implements actions necessary to enhance energy systems, and provides energy counsel to the Governor's Office and the recommended Multi-State Energy Commission to promote a competitive, economical and reliable energy market for all Delaware consumers.

Actions in process

1. Electric distribution companies, as members of PJM, are recognizing better approaches to managing costs under the LMP system and have made some progress in using limited Fixed Transmission Rights (FTRs) to better hedge congested energy costs.

2. As previously mentioned, the recent PEPCO/Conectiv merger settlement, as approved by the Commission, established threshold limits for qualified hours of congestion.[33] The provisions of the settlement expire in 2006.

3. The Delaware Public Service Commission Staff monitors federal, state and regional issues impacting energy in Delaware, although regulatory authority is limited. Other Delaware agencies monitor those areas that can impact their rules and regulations.

Recommended non-legislative actions

The Delaware PSC needs to continue its role in monitoring and participating in the development of FERC/PJM rules for transmission expansion and upgrades for economic reasons to determine their effectiveness in addressing the immediate impact on congestion issues within Delaware. The support of the final FERC/PJM proposal by the DE PSC will help speed implementation of this process. Estimated cost to monitor and participate in PJM activities is approximately $150,000 per year.[34]

[33] Conectiv/PEPCO Merger Settlement Agreement, Nov. 30, 2001, page 24.
[34] Estimated cost based on annual salary and benefits associated with one (1) full time employee plus administrative, travel and procedural costs.

Recommended legislative proposals

1. Delaware should establish a State Energy Coordination Stakeholder Group that monitors the Delaware energy planning process and the economic impact of electric and gas transmission system constraints. The Group, made up of interested stakeholders, should provide energy counsel to the Governor's office and the Multi-State Energy Commission, make recommendations for system enhancements and help to sustain competitive consumer energy costs. Specific responsibilities would include:

    - identifying energy concerns,
    - identifying potential solutions and proposals,
    - coordinating energy improvements
    - providing guidance and direction on energy policy,
    - establishing implementation plans, and
    - implementing state energy solutions or directives.

2. In January 2004, Delaware PSC should formally review the FERC/PJM proposal to evaluate the effectiveness of their processes to determine if further intervention and/or legislation is required to assure the mitigation of the economic impacts of congestion in Delaware.

3. With PJM growing rapidly in size and scope, it will be even more important for Delaware to have a cohesive state agency that provides energy planning direction/coordination and has the resources needed to meet energy policy objectives. Legislation authorizing such agency may be required, depending on the extent of responsibilities

Areas for further evaluation or research

Old Dominion has noted that in the short term, actions must be directed toward mitigating congestion costs immediately. They have proposed a mechanism designed to achieve this goal by requiring a modification to the methodology for determining congestion costs. According to Old Dominion, its specific primary goal is to minimize the financial burden any market participant must bear as a result of the existing conditions in PJM's transmission network unrelated to the formation of a wholesale electricity market. Although the mechanism strives to eliminate the harm to consumers from existing conditions in the transmission network, going forward it still sends the market-determined locational price signals to all market participants so that consumers will make the appropriate electricity consumption decisions and producers the appropriate investment decisions. This process, if adopted and approved, is still a transitional issue and while its' attempt is to protect the consumer, it does not fix the transmission system to withstand long-term congestion. Attachment E contains a more complete description of this mechanism and should be further evaluated.

ALTERNATIVES TO ELECTRIC TRANSMISSION CAPACITY AND RECOMMENDATIONS

Adding electric and gas transmission facilities is but one method to help ensure reliable, low-cost energy for Delaware consumers. There are alternatives available in the marketplace that should be thoroughly examined, may help ensure reliable, low-cost energy, and may also supplant transmission capacity requirements very effectively. For the most part these include base load generating plants, distributed generation, demand response programs or competing fuel availability. But again, dependent on the market force decision process, these alternatives may or may not develop in a timely fashion or in adequate volume to make a significant impact on Delaware energy needs. Each of these alternatives also come with significantly different cost structures and their desirability from a business perspective remains open to question

In addition, the various energy alternatives in Delaware each carry different environmental considerations. A gas pipeline enhancement means new homes and industry burning gas. Base load generators come with various levels of SO_x, NO_x, CO_2, and other air/ground pollutants. Distributed generators disperse the air pollution across broader regions, but may actually increase it depending on the technology used. Demand response is one of the cleanest options in that it actually reduces the need for energy. In comparison, increased electric transmission capacity may bring with it land use issues, while often impacting the air quality of other states. Environmental impacts need to be considered with alternative energy transport mechanisms and included as part of an economic modeling process.

Generator Interest

From an energy transport perspective, the availability of transport capacity is often interchangeable with supply. An electric generator, located in a specific area, can negate the need for a transport capacity and similarly, a higher level of transport capacity can negate the need for a generator. In the early 1970's, vertically integrated utilities often compared alternative generation and transmission projects to determine the most cost-effective solution to provide needed capacity. In many cases the investment in a 10 or 20 MW diesel generating station was the most cost-effective alternative and delayed other capacity investments for a substantial period of time. Now in a restructured environment there is some degree of conflict, with an unregulated generation affiliate or independent business seeking generator business opportunities, while at the same time the regulated utility is looking at necessary capacity additions. To the extent Delaware desires additional generation as an alternative solution, we are left in a position of providing some type of encouragement to the unregulated business environment. Moreover, environmental concerns also conflict with some of the lower cost generation that could be targeted to negate the need for transport capacity.

The addition of base load generation would not only replace the need for transmission additions, but could also be a solution to congestion on the Delmarva Peninsula. Some believe that locating generation on the Peninsula would be the optimum way to deal with congestion and the current limitations of the transmission system to import supply to the Peninsula in the most efficient manner.

Although adding new generation is a viable option, there are several serious impediments to locating such generation on the Peninsula. First, because of environmental concerns, there are significant limitations to new generation being sited. Under the Federal Clean Air Act, the Peninsula is in a non-attainment zone, which places severe limitation on the release of airborne contaminants, impacts the type of fuel sources that can be used and limits the period of operation of the generating units.

Natural gas as a fuel source to be used by an electric generating plant has been considered by many to be more environmentally friendly than other fuels like coal and oil. However, the availability of natural gas is severely limited because of the lack of natural gas transmission lines on the Peninsula.

Despite the positive implications associated with this alternative, some utilities feel severe restrictions will continue to reduce the attractiveness of this option. For a developer to locate on the peninsula, the developer must be able to build the generation project at a comparable cost to a similar project outside of the peninsula. LMP signals alone, even if the developer were very good at their prediction, would not be enough to guarantee that such a substantial investment would be made. During the course of constructing the unit, assuming that the decision was made to proceed, other solutions may be implemented that reduce the congestion cost to zero. These other solutions could entail additional transmission capacity, significant demand response or even other generation; all of which could reduce the expected return on the investment.

Distributed Generation[35]

Distributed generation ("DG") refers to electricity generation technologies that are relatively small in size and can be deployed close to customers within the distribution system, as opposed to being located on or near the transmission system. Such generation technologies can be installed by customers in order to reduce overall electricity costs and improve reliability, or they can be installed by the distribution company as a low-cost means of addressing demands on the distribution system. DG has been billed as one of the best ways to increase capacity in areas where there is limited generation supply and to reduce outages caused by distribution system failures. When advantageously sited, it can also reduce transmission constraints. Currently, most DG on the Peninsula is provided by diesel generators. Although relatively inexpensive to operate, these units have adverse environmental impacts because they emit relatively large amounts of NOx compared to natural gas fired generation. Other DG technologies include fuel cells, renewables such as photovoltaics, wind turbines and microturbines.

Distributed generation includes both generation and other items such as energy storage equipment. The equipment we categorize as distributed generation can vary from a few hundred watts to 10MW. The equipment by definition is scattered throughout the power system. It may be connected to or be isolated from the grid. The equipment may be fossil fueled, be a renewable source, or be a storage type device. See Attachment F.

[35] This section has been supplemented by Conectiv Report, J.A. Elliott – 11/05/02

Equipment & Industry

Distributed generation equipment includes reciprocating engines, microturbines, wind turbines, fuel cells, and photovoltaics. A few other technologies such as Sterling engines, and combinations of the above clean technologies like fuel cells and microturbines round out the mix of generators. Storage devices such as flow batteries are showing promise for reducing system peak and relieving constrained feeders or distribution equipment.

Regulatory

For many years emission standards have been getting stricter and slowly states have begun enforcement even down to backup units. At the same time, regulatory bodies encourage green and clean technologies – sometimes with incentives or rebates. Emissions standards should be set for DG as a means of ensuring new installations know expectations in advance.

Potential New Approaches

Another approach may be the DG Parking Lot concept. The concept involves siting future substations close to gas supply and purchasing enough extra space where trailer mounted DG units can be located. This can provide long term or interim localized supply additions. With the DG units fueled by natural gas, the success of this concept is dependent on the availability of adequate gas fuel sources and high customer load concentrations in close proximity to the DG location. These units would take the place of system upgrades and therefore cost recovery for related expenses incurred by the DG developer may need to be considered.

The application of DG can also offset losses on the transmission and especially the distribution system. If losses are tracked, accounted for and compensated for differently, or the company can get financial credit for reducing losses, then DG may become another driving force that will help cost justify installations versus making transmission and distribution upgrades. This would also need to be factored into rate or cost recovery options.

Tracking and Monitoring

One issue with DG is the masking of system delivery capability. Today the delivery system is planned based on metered load and any demand reductions added back to the metered load to develop an "unrestrained peak". This peak is the true delivery requirement if the customers elect not to use their DG or if it is operationally unavailable due to forced or planned outages. As a system is planned some assumptions must be made on equipment availability. Operational failures will occur at some rate and must be allowed for as part of the planning process. Some mechanism or agreement on the assumptions will allow for more reliable planning. DG programs, equipment installations and performance results needs to be tracked by an appropriate state or regional authority to ensure adequate recognition in the planning and operational processes.

Social Acceptance

A major unanswered question is whether the consumer will embrace the DG concept and become more than a passive participant in the energy process. We have no indication that consumers want to have small generators in their backyards to oversee and provide maintenance to these devices. The costs tend to be prohibitive for even consumers of novel interest to invest in the equipment. We also have seen that most consumers are satisfied with the reliability of their service and therefore have not seen it necessary to invest in DG for service security. The most likely outcome appears to be the local utility adopting DG as a part of the delivery system and DG is utilized as an integral part of the planning process. Tariff changes may be required to better allow for DG as a tool in the resource portfolio.

Technical Interconnection

Even though these are small generators, they bring some of the same challenges that large generators do for a delivery system. It is critical that the generators have the proper protection equipment that can monitor the generator's operation and isolate it from the delivery system during fault conditions. Otherwise the operation of the generator could impact the reliability of the system. Also, any units that expect to operate in parallel with the delivery system must have coordinating protective systems that coordinate with the electrical system as a whole, must be tested prior to installation for proper phasing relationship and should be tested and maintained on a planned cycle. The utility system that will connect to the DG should have standards for interconnection that apply consistently to all installations.

Demand Response

Demand response is essential in electric markets to address price spikes, reliability concerns and market power issues. Robust competitive markets depend on the interaction of demand and supply. For the most part, demand response is missing in today's electric markets.

Price spikes have been a recurring feature of wholesale market since restructuring. High loads during the peak summer periods in PJM cause prices to spike as do increased fuel costs. "The pattern of prices within days and across months illustrates that prices are directly related to demand. The fact that price is a direct function of load illustrates the potential significance of price elasticity of demand in affecting price.[36]"

Reliability concerns occur when loads are too high. This can be because of generation resource shortages or transmission or distribution system congestion. In addition, high market concentrations on the Delmarva Peninsula during periods of congestion can create the potential for local market power abuse[37].

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[36] PJM Interconnections's State of the Market Report 2001, page 6.

[37] According to the PJM Interconnection State of the Market Report for 2001, market concentration ratios, as measured by the Herfindahl-Hirschman Index ("HHI"), of 3,500 to 10,000 occurred on the Peninsula during periods of congestion. FERC, in its merger review process, considers HHIs above 1,800 to be problematic.

Demand response can take several forms, including energy efficiency, active load management, and DG. Energy efficiency is using less energy/electricity to perform the same function. Energy efficiency programs are designed to use electricity more efficiently -- doing the same with less. Energy efficiency opportunities abound, such as constructing buildings with more effective insulation, retrofitting lighting to use more efficient products and using more efficient heating and air conditioning systems. Active load management consists primarily of utility initiated direct control (direct switching of air conditioners, water heaters, swimming pool pumps, etc.) and contractual interruptible load. DG typically takes the form of customer owned generation operated during peak load periods to reduce energy cost.

Demand response has several potential benefits. One of the most significant, as discussed above, is the ability of demand response to moderate price spikes. For example, it was determined that on June 7, 1999, during the peak hours, a 4% reduction in demand would have cut the hourly real-time market price by almost 50%.[38] Some of this price reduction would have been realized by the entities responsible for the demand reduction, but most of the benefits of the price reduction would have been socialized to the remainder of the market participants' purchasing power in the real-time market. This ability to affect prices also makes demand response an important tool to address potential supplier market power. Demand response could also reduce costs through lowering transmission congestion costs, if DR were employed during periods of congestion.

To the extent that demand response reduces system peak demands, fewer generation resources, transmission and distribution infrastructure would be required. During the hot, humid summer periods, when loads and prices are the highest, lowering load through demand response might also reduce the use of the generating facilities that normally operate during peak load periods that adversely affect the air quality in Delaware such as diesel or oil-fired plants.

There are significant barriers to implementing demand response programs. These include the lack of time-variant meters and tariffs, particularly at the residential level, that would allow the consumer to "see" the price of the electricity consumed. The price could vary hourly or perhaps vary during off-peak and on-peak periods within a day or week. An advanced metering pilot program will begin soon in Delaware to study these issues.

Although not currently a PJM policy, many market participants in PJM support the concept of allowing load to bid into the PJM energy markets on an equal footing with generation resources. This would allow load to receive the same marginal pricing benefits as resources. The ability of the load reductions to actually perform when called upon and the difficulties of measuring those reductions are among the impediments to implementing such a policy.

Another impediment to the development of more demand response is that, as previously discussed, all participants in the spot energy market benefit when load is reduced, but the costs of those load reductions are borne by the few. A more direct linking of costs and benefits could create an incentive for more demand response. This would require a regional

[38] Hirst, Eric. March 1, 2001. "Price-responsive Retail Demand: Key to Electricity." *Public Utilities Fortnightly* p. 34.

approach since the electric grid does not recognize state or jurisdictional boundaries. Different jurisdictional approaches to these issues are another barrier to successfully developing more demand response in the Mid-Atlantic region.

Load-serving entities that would be integral to the implementation of most demand response programs have no economic incentive to participate in such programs. Every kilowatt-hour reduction of electricity usage translates into lost revenue for the company that delivers the energy. Prior to restructuring, vertically integrated utilities had the ability to compensate for such losses of transmission and distribution revenues by the savings achieved by the energy supply function. Since restructuring, the delivery company no longer has this ability. Developing mechanisms for sharing the savings with the delivery companies is essential to the success of demand response.

The ability to aggregate small loads, such as residential and small commercial, would allow for more effective demand response implementation. Market rules should allow for aggregation of load.

Recommendation #4 – (Important)

Delaware should encourage the development and use of energy capacity alternatives by providing economic incentives, incorporating the use of alternatives in the regional energy planning process, and when necessary mandating beneficial programs.

The alternatives of base load generation, distributed generation and demand response offer significant opportunity to help defer expensive transmission capacity additions. However, each must be examined in the broad context of state energy policy to ensure that they can meet targeted energy objectives at the most economic cost.

Actions in process

1. PJM offers demand response programs for both emergency load reduction and economic cost reduction aimed at large wholesale customers, and designed to offer peak load reductions as operationally required.

2. Many private firms offer energy efficiency services and can provide distributed generation alternatives to customers desiring the added security or potential energy demand and related cost reductions; however, there is little coordinated management of these resources.

3. Base load generation, as an alternative to transmission, is dependent on the marketplace decisions of unregulated energy companies. The Peninsula continues to see moderate increases in new generation, helping to reduce the need for transmission investment.

Recommended non-legislative actions

1. To encourage the development and expansion of natural gas transmission and development of new generation, Delaware should consider the following options:

   - Federal, state and/or participant funding of such a project.

   - Encouraging the FERC to allow the expansion of the natural gas lines and agreeing to support the natural gas supplier's application to include the cost of the expansion in its rates. Obviously, the rate impact of this option is a major consideration.

   - Sharing cost reduction benefits (transmission and congestion savings) collected from the load with the proposed generator.

   - Gas pipeline fuel availability to a generator at costs comparable to other locations where infrastructure exists, subsidized by state funding or rates paid by gas and/or electric customers.

The estimated cost of these options is dependent on the cost of the anticipated facility and the method by which the investment is funded.

2. Delaware should actively support the development of "clean energy" [39] distributed generation and demand response programs that are consistent with Delaware's economic and environmental requirements. Utilities should be encouraged to establish generic interconnection procedures and to work with distributed generators to assist in connecting to the transmission or distribution system.

3. Delaware should support the broader application of demand response to retail customers, including the development of market aggregators and an active MW demand response trading market. Although not a direct cost to Delaware, there would be PJM member costs associated with the establishment of the trading market.

4. Delaware should continue to encourage the development of merchant transmission business as a potential alternative/supplement to regulated transmission expansion and investment.

   § Participate in and support the development of PJM's merchant transmission business rules that provide for an equitable return on transmission investment.
   § Evaluate the opportunity for merchant transmission to provide energy capacity in Delaware and identify business entry barriers that may prevent merchant development.

[39] Definition, Appendix B

- § Provide executive/legislative advice for actions that may be required to encourage merchant business and to provide Certificates of Public Convenience and Necessity ("CPCNs") for transmission access in Delaware.

5. Delaware agencies should consider the implementation of an education/outreach program designed to educate consumers about the benefits of conserving energy during peak periods and how power markets operate to impact energy prices.

Recommended legislative proposals

None

Areas for further evaluation or research

The ultimate success of distributed generation, or demand response as an alternative to capacity additions, is dependent on customer acceptance and willingness to begin managing energy costs. Historically, retail consumers have accepted regulated energy pricing with little concern over the ways in which they could manage costs. Additional study is necessary to determine the best way to encourage retail consumers to view energy cost as a manageable commodity and to take voluntary actions that may be in the best interest of themselves and all other consumers.

Delaware should explore the possibility of legislation authorizing the Public Service Commission to mandate cost-effective retail demand response and environmentally acceptable DG programs, which could include provisions for tax and/or economic incentives to encourage the development and use of energy capacity alternatives.

SECURITY ISSUES AND RECOMMENDATIONS

Although utilities have typically been prepared to respond to natural or weather related disasters, the possibility of man-made disasters is a recent concern that can have a major impact on both generation and transmission capacity. It is essential that emergency planning consider additional security enhancements to minimize the impact of all disasters that may result in the loss of energy generation or transport.

Security of Transmission Assets

It is important for Delaware to maintain security and control of its transmission and distribution capacity resources. Emergency circumstances are difficult at best, but they can become insurmountable when coupled with the loss of energy to homes, industry and emergency facilities. With transmission and distribution facilities spread across the nation, one must realize that it is an impossible task to assure the safety and continued operation of the entire system. Although PJM has continuously operated the electric transmission grid in and effective and reliable fashion, the damage from a major storm or other disaster could easily render transmission equipment inoperable over large portions of the system. This would result in temporary energy supply reductions and many areas being without electricity. Under these circumstances, state contingency plans could be activated in similar fashion to hurricane or other emergency response efforts. Citizens of Delaware could be advised of areas where they could seek shelter and await the repair of facilities and restoration of service.

Damage to transmission capacities, other than electric, has a tremendous potential for not only interruption of supply but of significant collateral damage to surrounding facilities. Gas and oil lines, tanker trucks, rail cars and barges have lethal potential when damaged by natural or man made events. Where fuel supplies to power plants can be interrupted for long periods, the loss of energy to the transmission grid can be a real possibility. Homeland security officials need to be cognizant of the locations, and volume of energy transport mechanisms and be prepared to respond to major supply reductions. State regulatory agencies need to make sure that all public utilities have emergency plans in place that provide backup services that are essential to the operation of the energy capacity resources.

Recommendation #5 – (Critical)

Delaware agencies (particularly, the Delaware Emergency Management Agency, "DEMA") should continue to coordinate with Homeland Security and other appropriate agencies to assure the security of existing energy transport facilities.

Actions in process

1. Delaware continues to refine emergency plans. In January 2002, Governor Minner announced the appointment of Delaware's Homeland Security Advisor, whose main

responsibility would be to ensure coordination between federal, state and local government agencies as well as private sector organizations on issues of public safety and emergency preparedness.

2. In addition, DEMA and the various utilities continue to conduct emergency preparedness drills and to develop new approaches to managing natural or man-made disasters.

3. DEMA is developing a statewide all hazard mitigation plan addressing natural and manmade hazards including terrorism and Weapons of Mass Destruction. This plan will specifically identify mitigation projects to the municipal level

Recommended non-legislative actions

1. All state agencies should review potential energy disasters, establish approaches to deal with the events and conduct simulation drills designed to minimize state impacts. In addition, state agencies should conduct annual audits of existing utility plans and practices designed to maintain the security of critical assets. Estimated costs are mostly administrative and limited to resources necessary to conduct drills.

2. State agencies need to encourage tighter restrictions on access to rights-of-way and critical transmission and distribution facilities, particularly where they may be exposed to road, water or rail transport. Estimated costs are dependent on extent of facilities with restricted access and the type of restrictions imposed.

Recommended legislative proposals

None

Areas for further evaluation or research

Delaware should review the current emergency response laws and the authority of state agencies to impose them on the energy industry. The review should include an assessment of the need to establish or enlarge existing energy security standards via legislative intervention or assistance.

TECHNOLOGY ISSUES AND RECOMMENDATIONS

With the increasing pace of technological advancement, it is important that energy companies explore potential new approaches to planning and managing their transport systems. The application of new technologies can often deliver operational improvements with minimal economic cost.

New Technologies

New electric transmission technologies and their applications continue to emerge. Real-time ratings, improved ambient condition assessments, demand response applications, distributed generation, and many other technologies offer opportunity to enhance the existing capacity of our electric and gas transmission systems. However, utilities have been generally slow to make major investments in new technologies due to both operational and financial risks.

In addition, many of the new technologies for enhancing capacity are for small, short-term enhancements and cannot begin to provide the level of reserve margin that a robust transmission system would require. A move to real-time ratings, as an example, can provide increased capacity, but only one time unless other technologies are employed. New technologies have been available for many years but relatively few concepts actually emerge with credible staying power.

A truly competitive electric market might easily lead to the endorsement of the latest technology as long as it provides benefits for the end-use customer through lower costs. Firms will have an incentive to apply the newest technologies as long as it lowers their cost of doing business. If that lower cost (or enhanced delivery with the same cost) is passed on to the consumer, then all parties benefit and the technology is successful.

Recommendation #6 – (Important)

Delaware regulatory agencies should support the development and application of new cost-effective technologies for energy transport facilities.

Actions in process

The application of new technologies is currently done at the discretion of energy companies, when in their opinion, the technology is refined enough to provide continuing benefit. Delaware should consider supporting the recovery of technology investment when service and reliability are cost-effectively enhanced.

Recommended non-legislative actions

1. With the advent of new technologies, Delaware should encourage power companies to consider the installation of more real-time video monitoring of major power lines and substations. Installations similar to traffic cams could provide useful information during minor storm conditions and could certainly help prevent man-made disasters

or outages. Estimated costs are dependent on the technology and extent of its installations.

2. Delaware should encourage the development and deployment of new cost-effective technologies that enhance energy capacity.

    a. Provide for a regulatory pre-approval process (for revenue recovery) related to new technology investment to be administered by the Public Service Commission.

    b. Consider the adoption of legislative authority to ensure cost recovery for implementation of new technologies to enhance energy capacity.

    Estimated cost would be primarily administrative in the conduct of any hearings or reviews.

Recommended legislative proposals

None

Areas for further evaluation or research

Utilities suggest that FERC and state commissions provide incentives for companies to adopt new technologies that appear to have significant benefits to consumers and shows promise of being cost-effective. Incentives to expand research and development for new technologies should also be considered until such time that it is apparent that a fully competitive marketplace exists.

LAND USE ISSUES AND RECOMMENDATIONS

Whether one is contemplating a generation station, distributed generation, or an electric or gas transmission line, there are land planning, zoning, siting and environmental issues that may pose significant barriers to the proposed project. There are right-of-way acquisition issues, land value issues and the aesthetics of the local community to be considered.

Siting and Permitting Issues

There are sixty "local" governments in Delaware: three counties, and fifty-seven municipalities. Land use, for the most part, has been deemed by the General Assembly to be a local issue. Authority over land use has been granted to the counties through provisions in Title 9 of the Delaware Code, and to the municipalities through provisions in Title 22.

Local governments control land use through the adoption, implementation, and enforcement of regulations typically referred to as a zoning ordinance (in New Castle County, these regulations are contained in the County's Unified Development Code). The counties and, presumably, the municipalities (time did not permit the review of fifty-seven land use regulations) treat public utilities as a conditional use: that is, permitted but subject to additional conditions, usually in the name of "health, safety, and welfare." Conditional uses (at the county level) are subject to public hearings by the planning boards/commissions of the respective counties and the county council (in Kent County, known as the Levy Court). Both the planning board and the county council can place additional conditions on the project.

There are also several state agencies that play a role in the siting of public utility generation, transmission, and/or distribution facilities. The Department of Natural Resources and Environmental Control ("DNREC") issues permits for air emissions as well as permits involving wetlands or subaqueous lands. The Department of Transportation ("DelDOT") has control over street rights-of-way, which has been discussed in terms of co-locating transmission and distribution facilities in existing rights-of-way. One could argue that the development and expansion of public utilities is an integral component of the state's economic development program; therefore, the Delaware Economic Development Office ("DEDO") should be involved.

The Office of State Planning Coordination ("OSPC") also has a role to play. It should be noted and emphasized, however, that the OSPC is a coordinating, as opposed to a regulatory, agency. Having said that, the OSPC is already quite effective in addressing and coordinating land use issues and activities between state and local governments, as well as between state agencies. It has been suggested, for example, that there be an inventory of sites throughout the Delaware that are zoned for industrial use, with access to water and other infrastructure, that could be used for generation facilities. This seems like an appropriate task for the OSPC (possibly with some assistance from DEDO).

In summary, it would appear that the issue of siting and permitting public utility generation, transmission, and distribution facilities is more than simply a local issue, which is what the current system is designed to address. At the very least, siting requirements should be a statewide (if not regional) issue. Therefore, a mechanism, or system, is needed to address the issue at the state level.

Rights-of-Way Acquisition

Obtaining right of way for new electric transmission facilities is becoming increasingly difficult. Right of way that can be permitted and is suitable for building transmission facilities is becoming more scarce and valuable, and there are aesthetic concerns from the general public around electrical transmission facilities. A utility can be successful in negotiations for a majority of a proposed route, but one or two landowners can stop the entire project by refusing to negotiate. It is possible for a landowner to delay construction of transmission facilities for extended periods by virtue of withholding land rights. With the current rate of load growth, a delay or cancellation in a project can lead to supply and reliability concerns. There is also the concern for the "Not In My Back Yard" mentality which is almost always present at public hearings. A transmission line is usually beneficial to the entire state or region, but nobody wants it in their backyard. These problems will only increase in the future. Delaware is one of only a few states in the country that does not grant condemnation rights to electric utilities nor has a state siting process that ultimately resolves these issues. Utilities would much rather negotiate with property owners for rights of way, but the condemnation alternative does help the negotiations along and precludes one land owner from unreasonably withholding the granting of an easement or demanding unjust compensation for such easement.

The right of condemnation is a critical issue for energy utilities. Gas transmission companies have eminent domain through federal legislation and United States Representative Joe Barton's recently introduced energy bill includes a provision for electric eminent domain for critical transmission lines where states fail to provide siting within a one-year timeframe. Without eminent domain, projects can be delayed or even canceled and may experience significant increased costs. There have been several projects on the Delmarva Peninsula that have been delayed by the absence of an eminent domain process. Each of these projects have also accrued higher costs due to the need to pay landowners higher than market prices or the need to reroute transmission facilities.

- <u>Indian River to Milford 230kV line in Sussex County, DE</u> – This line was constructed in the mid 1970's from the Indian River Power Plant to Conectiv's Milford Substation. A major landowner in Sussex County would not negotiate with Conectiv for right-of-way which was needed for the upgrade to the substation. The difficulty was that this landowner owned much of the property surrounding Indian River Power Plant. Even after cordial communications between the parties, the landowner had no interest in conveying any property rights to permit the construction of this addition. This caused many redesigns, and the line was actually built using 45 higher-cost angle structures in the 26-mile line.

- <u>Cedar Creek to Milford 230kV in Kent County, DE</u> – This line was constructed in the mid 1970's between Conectiv's Milford Substation and Cedar Creek Substation. There were many landowners that declined to discuss property rights with Conectiv. As a result, there are 67 additional angles in this 43-mile line.

- Easton-Steele 138kV in Maryland – This line was constructed in the early 1990's between Conectiv's Easton Substation and Steele Substation in Maryland. Conectiv was having difficulty securing rights for this approximately 25-mile line. It was only after Conectiv obtained the CPCN from the State of Maryland, which threatened condemnation rights, that easements were successfully negotiated. [40]

In the first two examples, the projects were delayed as Conectiv was forced to redesign their lines to include heavy angle structures with increased anchoring requirements and self-supporting structures at significantly higher costs. Where a typical mile of transmission line may be built with 12 to 15 in-line (tangent) structures, the need to turn corners or bypass existing properties will usually include at least 2-3 angle structures and may reflect a 21% increase in cost for a mile of construction. While 230KV transmission lines are currently estimated at $700,000 per mile, the requirement to include angle structures could escalate that cost by an additional $140,000 - $150,000 per mile.

Transmission line redesigns, made necessary by reluctant landowners, can also create other problems for utilities. Some rerouting leaves only wetlands or other environmentally sensitive areas as a plausible route, requiring careful planning, environmental permitting and mitigation efforts. There is also the potential for future costs when rights-of-way are limited or restricted. Where a utility plans to make a future use of existing rights-of-way for additional lines, it may be forced to use more self-supporting structures or obtain additional rights-of-way to compensate for the original insufficiencies.

Without the right of condemnation, there is also the possibility that a utility would be unable to build a planned capacity addition. This would likely require other facilities to be upgraded to transport anticipated energy loads and could result in increased periods of congestion, with higher risk of service outages. A sampling of some other states policies concerning right-of-way acquisition issues is contained in Attachment G.

Recommendation #7 – (Critical)

Delaware should simplify the permitting, siting and right-of-way acquisition process

In order to address the siting and permitting of public utility generation, transmission, and distribution facilities at the state level, consideration must be given to designating an agency that has the authority to overcome local (that is, county or municipal) objections or other obstacles, such as the NIMBY (Not In My Back Yard) arguments that are raised in many conditional use public hearings. This would entail the creation of a new entity or the enhancement of an existing entity such as the PSC, Office of State Planning Coordination, or Livable Delaware Advisory Council, etc., for the purpose of approving a transmission route and granting the right of condemnation to the utility.

[40] Maryland has a process which authorizes its PSC to approve CPCNs related to the siting of electric transmission lines.

Actions in process

None

Recommended non-legislative actions

Resolving siting issues and obtaining permits to construct facilities that can extend for miles across open farmland and other properties is one of the most difficult processes because of the number of variables that can impact the outcome. However, for the most part the process is heavily dependent on three key variables.

- Number of permitting agencies/governments involved
- Number and needs of land owners involved
- Utilities reputation and trust with land owners and permitting agencies

In many instances, it is through informal processes such as news stories and word of mouth that opinions are formed. Unfortunately this is not the best process for deciding issues that play such an important part in everyday life. To avoid decisions that are based on opinions that are formed without the necessary information, the Task Force recommends three approaches that, although currently in use, could be enhanced.

1. Establish a more comprehensive and cohesive approach to acquiring the permits and land rights, supported by a single state agency. A public meeting, or series of public meetings, early in the process, sponsored by a state agency, with all interested parties in attendance, (and preferably before the developer/utility has a project mindset) would provide a better forum to address and receive input on issues such as project need and property valuation. This process could improve the likelihood of buy-in to a project at an earlier stage. At a minimum, all interested parties will be better informed.

2 Explore non-traditional options to payment for right of way from landowners. Offer potential non-cash options as incentives to gain landowner agreement. This could be as simple as declining property tax assessments, or as complex as alternative property transfers, lifetime annuities, insurance or whatever provides an acceptable value to the landowner. Subject to a fair market value test, the alternative incentive (perhaps untaxed) could be a significant inducement to obtaining agreement with the landowner.

3 Consider the expanded use of the state highway system or railroad rights-of-way as potential corridors for an expanded transmission system. Many of these transportation systems have major north/south and east/west corridors and to the extent they are cost competitive with private rights-of-way, they may provide a significant alternative. However, it would still be necessary to negotiate private rights-of-way when projects extend beyond the existing corridor.

Recommended legislative proposals

Delaware should ensure public utilities the ability to obtain right of way for transmission projects at a fair market price within reasonable design guidelines and also ensure the ability to permit and construct the line. The following legislative action is proposed:

1. Create a new state authority or empower an existing state body ("Siting Board") to approve the need, the route and the right to condemn property for a project when requested by the utility. This state authority would:

   - Approve zoning and land use permits at a state level as opposed to a local level when the project affects more than one local government.

   - Ensure that appropriate public hearings are held and a timely decision is rendered by the approval authority.

   - Ensure landowners receive a fair market value with opportunity for value arbitration as necessary.

   - Ensure the utility can begin construction in a timely fashion.

2. This proposed legislation will require the utility to select the most viable route for the new transmission line based upon permitting, right of way, environment, ease of construction and whatever other parameters apply. The proposal would allow the utility to apply for condemnation rights and zoning relief on a particular line, but it does not grant "blanket" condemnation rights to the utility. Estimated cost is primarily legislative, with approximately $150,000 annually for one employee to monitor and manage the process.[41]

Areas for further evaluation or research

None

[41] Estimated cost based on annual salary and benefits associated with one (1) full time employee plus administrative and procedural costs.

FINANCIAL ISSUES AND RECOMMENDATIONS

The objective of the "Financial issues" subgroup was to address cost recovery of needed transmission and distribution infrastructure upgrades and improvements in Delaware, while balancing the financial risks and interests of regulated utilities, retail customers, shareholders, and any other third party that may have an interest in the network. The "financial issues" subgroup of the Transmission and Distribution Work Group addressed several different areas around who should pay for needed transmission and distribution upgrades.

There are several key principles for transmission and distribution cost recovery that need to be considered when discussing the appropriate method of cost recovery and financial issues.

- Pricing mechanisms should allow timely recovery of fixed and variable costs.
- Pricing and cost recovery should be assigned consistent with the use of the system. Cost responsibility should follow cost causation.
- Cost recovery computation should include a fair and reasonable return on equity for owners that provides:
  - § adequate opportunity to attract capital,
  - § compensation for business risk,
  - § incentives for system expansion,
  - § full and timely recovery, and
  - § just and reasonable rates to consumers.
- Regulated cost recovery should depend on the methods and processes determined to be the most efficient for all parties.

Specifically, the "Financial Issues" sub-group addressed general cost recovery, market funded transmission and alternative funding sources. The sub-group recommendations and conclusions are listed in the discussion below.

General Cost Recovery

The following parties have been identified as potential sources for financing the costs associated with the expansion of electric and gas transmission facilities in Delaware:

1. Electric and natural gas retail customers or end-users within respective utility service territories.

2. State and local governmental agencies - State of Delaware (i.e. – taxpayers within the State of Delaware or counties)

3. Third party unregulated electric and natural gas marketers and suppliers – (i.e. builders of new electric generation)

Potential Types of Cost Recovery Mechanisms

While not an exhaustive list, the following are the various types of cost recovery mechanisms that could be initiated and implemented to pay for needed electricity and natural gas expansion projects:

1. Potential electric and natural gas distribution expansion costs could be recovered from existing and prospective regulated utility retail customers. All retail customers, or only those who directly benefit from the expansion, may share in these costs

    a. Potential expansion costs may be included in a regulated utilities' rate base with an associated return on investment included in its base tariff rates if costs are to be recovered from all respective customers. As base rate increases are not normally a routine occurrence every year, a regulatory asset could be established and later recovered over a certain period of time.

    b. In the event potential expansion related costs are recovered from certain customers, a surcharge mechanism could be implemented. This surcharge could be a volumetric surcharge or a fixed surcharge and would capture the natural gas or electric expansion related costs as well as a return on investment.

2. Expansion projects could be funded by the state or the local governmental authorities that benefit from these projects

3. Other interested third parties, such as developers of electric generation, should also have a certain degree of financial responsibility associated with a new electric generation project they develop. Any new generation project will create the need to upgrade transmission facilities to accommodate the project. The current PJM rules include the provision for the generation project to pay for interconnection costs and required transmission upgrades.

Market Funded Transmission

Merchant transmission is a relatively new phenomenon. In fact, merchant transmission business rules have just recently been filed by PJM. Essentially, merchant transmission is commercial transmission investment made in response to market based incentives. It is suggested that merchant transmission can help create a more competitive energy market by providing alternatives to regulated utility investment or expensive generation projects. It is important that projects proposed via this mechanism be able to compete on a level playing field with similar projects proposed by regulated utilities. Reliable and economically sound merchant transmission projects should be encouraged.[42] The challenge for PJM is in creating

[42] One Delmarva utility does not believe that merchant transmission is a viable option now or in the foreseeable future. While not necessarily representative of the Work Group at large, this utility cites several reasons why a merchant transmission option may not be viable. First, given the uncertainty in the industry and, in particular with the conditions in a load pocket, it is very doubtful, in this utility's perspective, that a merchant company

a realistic economic environment in which commercial development can come forward and meet all the relevant cost-benefit and market criteria. Such a project could be identified as "critically needed to support competition," and in such a case, the beneficiaries of the project [not transmission ratepayers generally, but the customers of the load serving entity ("LSE")] could pay for it through a special rate surcharge. The surcharge could be based on the projected value of market rights, primarily the congestion-relief benefits of the merchant transmission project provided that it results in just and reasonable rates. The viability of such projects rests on the criterion: Is there enough value to the market rights, primarily congestion relief, to provide an efficiency benefit in excess of the cost to construct the facility?

Alternative Funding Sources

PJM currently plans the transmission system for reliability. However, there are clearly occasions when transmission infrastructure upgrades are appropriate for reasons other than strict reliability criteria. In these cases the question arises, "Who should pay for these upgrades to the system if they are driven by economic purposes?" One answer to the question is to include the costs in the Transmission Owners' ("TOs") rates charged to all customers. Although any pricing mechanism will likely result in increased consumer rates, this section is meant to view possible processes by which funding could be made available for economic transmission enhancements.

First Alternative: RTO Stakeholder Process

For the electric transmission system, an RTO (PJM) should consider through its stakeholder process how to fund the infrastructure needed for non-reliability reasons. PJM has been discussing this issue and the issues should be expanded beyond merchant transmission

Second Alternative: Beneficiaries Fund Upgrades

The customers who receive benefit of natural gas and electric transmission infrastructure upgrades should fund them. If a generator needs a transmission facility built to move power to a certain area, the generator should pay for the upgrade. It would be the generator's responsibility to recruit customers to contribute to the cost of construction of

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could raise the capital required to build the project. Even if the capital were available, it may be cost prohibitive or require such a large return as to potentially make the project a non-viable option. Second, the utility suggests that there are other options for solving the congestion problem (and the subsequent high congestion prices) such as increased demand side response and various generation technologies that may be more cost-effective than merchant transmission and thus place that option at a disadvantage for financing purposes. Even if all of these impediments were overcome, merchant transmission companies may need high congestion prices maintained for many years in order to undertake the required investment risk. Additionally, it contends there is no guarantee that the state or federal government will sit and wait for a long time and watch consumers be exposed to local market power and the subsequent high congestion prices and not take action to bring down those costs. The utility suggests that this in itself may raise the uncertainty of an adequate return on investment and could likely forestall any merchant projects.

the transmission facility if the generator feels that paying for the upgrade would be cost-effective. Generators at present pay for transmission upgrades required to meet reliability criteria but not for economic transfers. The challenging issue is the determination of who benefits from the transmission expansion. This alternative becomes more complicated when you consider that the beneficiaries associated with projects could cross state lines. There is also the position that all consumers ultimately benefit and that the cost of the project should be socialized across the entire consumer base.

Third Alternative: State Funding of Upgrade to Infrastructure

The funding of the needed natural gas and electric transmission infrastructure could come from the State of Delaware in a number of ways. The State could create a fund that would be used toward construction of the facilities that are deemed to have economic benefit to Delaware. Another alternative would be to have the Delaware issue some form of lower costs debt to help finance the project.

As part of the state funding alternative, it could be appropriate to institute a pre-approval process through the Public Service Commission. This pre-approval process would allow certain transmission infrastructure upgrades to be approved for inclusion in rate base of the public utility for guaranteed recovery at the time of the next base rate proceeding. This pre-approval mechanism could address the risk of the utilities associated with recovery of projects needed for reasons outside of reliability. This pre-approval mechanism could potentially eliminate the uncertainty of recovery for the utility.

There is a diversity of opinion on the appropriateness for the state to fund transmission expansion for public or private companies. The users of electricity within the transmission owners system are the direct beneficiaries of the expansion and can reasonably be expected to pay for the upgrade. In most cases, the territory of the transmission owner does not cover the entire state so a blanket rule covering all state residents for payment would not be appropriate. However, if one takes a broader view of energy initiatives, in cases where one company's investment (such as a gas transmission pipeline) benefits the entire state population it may be appropriate to fund such projects through a state energy surcharge fund. Under any of the above possibilities, the state and participating utility would need to have agreement on facility ownership and assignment of business risk, such that Delaware citizens were not exposed to private business investment risk.

Fourth Alternative: State and County Funding of Upgrade to Infrastructure

The funding of the needed natural gas and electric transmission infrastructure could come from the counties in which it was determined that the transmission upgrade would provide benefits. The counties in conjunction with the State of Delaware could create a fund that would be used toward construction of the facilities that are deemed to have economic benefit to Delaware. The possibility of this alternative needs to be weighed against the cost to analyze the regional benefit by county. This approach more closely aligns the benefits with the costs; however, most upgrades have benefit well beyond a particular county boundary and current rate structures do not provide for geographic pricing, particularly at the county level.

Recommendation #8 – (Critical)

Delaware should ensure there is a fair and equitable investment recovery process for regulated and unregulated energy companies.

Consistent with the need for a regional planning process is the requirement to fund energy alternatives that may be necessary to support the resulting multi-state economic solutions. There was general agreement that those who benefit from capacity additions should have to absorb the cost, but from a regional perspective, the benefits of major system improvements would go beyond state boundaries and benefit entire regions. If one agrees that the consumers who benefit should pay for the broad based energy initiatives it becomes clear that a multi-state surcharge, administered by a regional planning commission, could be the most effective tool to meet regional energy needs.

In addition, state funding of regional enhancements, could be negotiated or bid through merchant companies or regulated utilities to ensure the most equitable result. The accumulation of financial rights and revenues could also play a key role in minimizing consumer costs on a regional perspective.

Actions in process

PJM has established the financial rights that should be accorded merchant transmission companies that invest in transmission and generation facilities. These rights are typically financed by load serving entities and provide payment based on the use of the facility. This method of financing private investment has been filed with FERC.

Recommended non-legislative actions

Delaware Public Service Commission should examine the possibility of a pre-approval process by which infrastructure investment is certified for rate recovery in the next succeeding rate case. Cost for this process would be limited to administrative filing and hearing costs, most probably on an annual basis.

Recommended legislative proposals

Consistent with the implementation of a Multi-State Energy Commission should be legislative authority to impose an energy surcharge on all ratepayers in the multi-state area. The Commission would be charged with administering the fund and ultimately paying for mandated enhancements that provide benefit to all ratepayers (basically financial administration of all socialized multi-state infrastructure requirements).

Areas for further evaluation or research

One funding alternative suggests the possibility of state funding, either via taxes, surcharges or bond sales. It is suggested that the finance office review this possibility for funding energy infrastructure investment that is mandated by state authorities.

A second alternative would be reversion to a regulatory regime that allowed the electric generating company full recovery of the cost of new generation in its "rate base." This ability could be limited to areas of congestion.

OPERATIONAL ISSUES AND RECOMMENDATIONS

There are various times throughout the year that the transmission system in Delaware, as well as the entire Delmarva Peninsula, is not available to move the lowest cost energy to loads. This results in higher electric costs to consumers in Delaware.[43] The Work Group has identified a number of areas where planning or operational changes could increase the availability of the transmission system on the Peninsula.

Coordination and Communication

These areas are enhanced coordination and communication among the system operator, transmission owners and system users in the areas of planning, maintenance and operations. When maintenance is performed on transmission facilities, some facilities might have to be removed from service for safety reasons. With these facilities unavailable, PJM's computer model[44] might show other facilities becoming overloaded in the next worse case contingency. This might require that local, more expensive and environmentally harmful generation be brought on line to serve the load formerly served by the overloaded facilities. If the schedules for such maintenance could be coordinated among the various parties, a decision to shift the maintenance to a more acceptable time period might be accommodated or the operations of the systems could be altered, such as switching load to a less congested facility during the maintenance period or addressing a potential overload by changing the circuit configuration. Such actions could reduce the amount of congestion on the system and reduce energy prices. However, shifting of maintenance schedules and the resulting impact on congestion patterns is a sensitive issue to some PJM stakeholders because of the potential for favoring or disadvantaging certain generation resources located proximate to the congested area.

The maintenance schedules for all transmission facilities in the PJM model are listed on the PJM website. This includes all transmission facilities that have an impact on congestion. PJM has very specific requirements for the timing of outage submittals. This advance notice allows market participants the opportunity to purchase Financial Transmission Rights (FTRs) in the monthly PJM market as a financial hedge against congestion costs. When the maintenance schedules for facilities under its control are submitted to PJM, it projects the impact of those outages on the level of congestion on the system. PJM discusses the reliability and any significant congestion impacts of these outages with the transmission owner that submitted the outage. PJM and the transmission owner jointly adjust the outage schedule as needed. PJM can cancel any outage for reliability concerns and any outage not submitted in accordance with the advanced notice requirements for congestion concerns. Ideally, access to these PJM projections would be a great help in the timing and operational decision-making processes of the parties. However, public dissemination of such

[43] Municipal customers are not subject to a rate freeze; Delaware Electric Cooperative and Delmarva Power & Light customers are currently under rate caps, but will be subject to the higher costs after the caps are lifted.
[44] PJM models available generation, load and transmission capability to determine whether all load can be served using bid-based dispatch, or whether transmission constraints will require generation be brought on line out of economic merit order.

information could provide opportunities for some market participants to change their generation bidding procedures to reap financial benefit from the transmission congestion.

Cooperation and Flexibility

After information is shared, the next step to increasing the availability of transmission would be cooperation among the parties in the way the systems are operated and in flexibility in scheduling maintenance outages. Besides transmission maintenance, coordination in the interconnection of new generating facilities might result in reduced transmission congestion**.** This type of intervention would need to happen quickly. A cumbersome process with disagreement among the parties could lead to maintenance not getting done, resulting in greater equipment failures and increased congestion costs. However, a streamlined, coordinated effort could provide beneficial results.

Coordination in the accomplishment of maintenance is another area the Work Group determined could maximize the availability of the transmission system. If either a planned or forced maintenance outage of transmission facilities occurs, it could be a benefit to the region as a whole to complete the maintenance during non-peak hours or complete the maintenance as quickly as possible. This could be achieved by either adding additional line crews or by working longer hours (during the night and on weekends) or both to complete the project. The parties affected could agree to pool maintenance personnel and equipment to complete the maintenance in the most expeditious manner possible. Issues such as work rules and safety procedures would need to be worked on prior to considering this pooling concept. Working additional Conectiv crews with cost sharing would be more immediately effective. Of course, an informal cost/benefit analysis of whether the benefit to the region of reduced congestion outweighs the additional costs, such as overtime, of the changes in the maintenance practices would be necessary. A cost sharing mechanism would also be necessary to allocate the additional costs among the parties that will benefit from the reduced congestion.

Recommendation #9 – (Important)

Delaware should encourage and support proactive communications among Transmission Owners, LSEs and PJM through the development of a working group to examine operational opportunities to minimize congestion especially during planned maintenance outages.

There can be opportunities to increase the available capacity of the transmission system and reduce the impact of congestion from an operating perspective, but it requires understanding the objectives of each party and communications with respect to issues and concerns.

Actions in process

1. PJM is the operational focal point for approving transmission construction and maintenance outages and general operations of the system. To the extent possible, outage information is routinely posted to their website for all parties. It is currently

the members' responsibility to respond to PJM if there are concerns over any planned activities.

2. An Administrative Committee that is made up of Conectiv, Old Dominion Electric Cooperative ("ODEC"), Delaware Electric Cooperative ("DEC"), Choptank Electric Cooperative ("CEC") and Accomac and Northhampton Electric Cooperative ("ANEC") was established to discuss issues regarding the interconnection agreement between ODEC and Conectiv. The committee is scheduled to meet quarterly and discuss project schedules, operating issues and concerns that arise throughout the year. This committee has historically addressed only operating concerns between the Transmission Owners and LSEs and has not addressed congestion, system constraints or resource sharing options to reduce congestion problems.

3. The Conectiv / PEPCO merger agreement outlines annual thresholds which differentiate between acceptable and non-acceptable levels of congestion hours on the peninsula and provides for provisions to address congestion fixes once congestion has occurred.

Recommended non-legislative actions

1. Establish a working group of Conectiv, ODEC, DEC, Delaware PSC, Delaware Municipal Electric Corporation ("DEMEC"), PJM and other LSEs as members/participants to improve maintenance and operational processes and practices to address congestion mitigation efforts. This group will not be involved in decisions on day-to-day operations, but instead will focus on process improvements.

2. Encourage PJM, LSEs and TOs to address the impact of congestion by highlighting outages that could result in significant congestion well in advance of the planned outage. In the existing process PJM notifies the Transmission Owner only 2 days prior to the outage about congestion or reliability concerns. PJM needs to give move data on congestion earlier in the process to promote discussions between Transmission Owners and LSEs. This will enable the LSEs in Delaware to work proactively and cooperatively on operating solutions to mitigate congestion during planned maintenance activities (Attachment H details the process)

Recommended legislative proposals

None

Areas for further evaluation or research

1. Delaware PSC should establish a working group to review the possibility of amending the current House Bill 10 to define facilities as either transmission or distribution depending on the function of the facilities, using the FERC seven-factor test as guidance. This approach is highly controversial, would have significant economic and operational impacts on the electric transmission system and is opposed by Conectiv.

2. Consider a proposal that would encourage operational alternatives to mitigate the affect of congestion including but not limited to the following:

    a. Providing innovative approaches to work schedules and resources by examining possible process improvements.

    b. Allow third party contributions to reduce the duration of outages for congestion mitigation. Attachment I details a process for implementation.

SUMMARY AND CONCLUSION

Transmission and distribution energy capacity in Delaware has provided generally reliable service to consumers. However, beyond that effort, there is a distinct absence of a coordinated energy policy to handle the complex issues of today's energy markets. Each federal, state or regional entity or regulated/unregulated utility company views energy issues from their own perspective. With the movement toward marketplace dynamics, each entity not only takes the actions that meet their regulatory responsibility, where regulation applies, but they also take actions to maximize their particular business opportunity. Even at the federal level, where one would expect a cohesive energy policy, there is limited coordination and a heavy reliance on marketplace financial signals and PJM requirements in the electric industry. The gas industry is even more fractionalized without the benefit of any regional oversight. The mere thought that an electric consumer should perhaps pay for a gas infrastructure enhancement as the most economic energy solution is almost never considered, nor are there any rate structure mechanisms to permit recovery of this type of investment cost.

Electric energy costs have been impacted significantly by system limitations that have driven the need for off-cost generation dispatch. Although market forces hold the promise of merchant investment to help resolve economic issues, this new development has been slow to offer any resolution to congestion costs. Gas energy is in short supply throughout much of lower Delaware due to the unavailability of transmission. In the more rural areas of Kent and Sussex County, gas transmission companies are reluctant to make major investments without a committed customer and conversely, customers are unwilling to make commitments due to the high cost for gas availability. There is no one agency or energy company that looks at the total energy picture and plans for the most economically effective approach to meet energy needs. The result of the current approach is not necessarily a loss of energy, but the absence of an energy management process that could ensure the best economic approach for the state or regional area along with lowest consumer costs. Without an effective energy management process, one is left with energy supply and demand curves, where demand is currently very inelastic and unable to impact energy prices to any significant degree.

Where there are alternatives to needed energy capacity additions, they have either not been fully developed or there has been limited business incentive to make the appropriate investment. New generation has been added on the Peninsula, but costs have generally been higher than typical base load units and have not resolved energy pricing issues. PJM offers emergency and wholesale customer demand response programs, but retail customer options are limited to the programs utilities are willing to support. Distributed generation is growing, but with limited regional oversight, it continues to be an underutilized resource.

There are land use issues, financial investment recovery issues, and operational issues that present significant economic barriers to new or upgraded energy capacity. Lack of a fair arbitration process in the acquisition of land or land rights and the risk of not recovering an investment in the regulated environment are suggested as obstacles to new investment. Additionally the need for operational interconnection testing, line maintenance, or forced outages can routinely create congestion pricing that can exist for an extensive period of time.

While this report attempts to address each of these concerns with a unique recommendation, it is apparent that an overall energy coordination, planning and management process at the state or regional level could provide a much more effective result. An energy management process that addresses energy issues in a broad context, and has the authority and resources to direct energy initiatives to meet regional needs is a critical component of a comprehensive energy policy.

Delaware Energy Task Force
Transmission and Distribution Work Group

Attachment A
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Attachment B
DEFINITIONS[45]

"Capacity Emergency Transfer Objective (CETO)" means the amount of megawatt capacity that an area or sub area must be able to import during localized capacity emergency conditions such that the probability of loss of load due to insufficient tie capability is not greater than one day in 10 years.

"Capacity Emergency Transfer Limit (CETL)" means the amount of megawatts that can actually be imported into the area or sub area during localized capacity emergency conditions.
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"Clean Energy" is defined as energy derived from highly efficient, clean technologies, including renewable "green" power and combined heat and power.

"Congestion" means the condition of an energy transport system during which time there are physical limits, transfer constraints or contingencies on the system, and during which other actions are required to maintain the secure operation of the system. Most notably, in the case of electric transmission or distribution, other actions may include operational switching or re-dispatch of generation to manage electric low flows on the limiting facility. Congestion may occur on other transport systems when because of customer demand, physical flow or transport limits are reached. This type of congestion can be resolved by load curtailment, flow rearrangements or the injection of energy supplies at other locations.

"Capacity" means the rated continuous load carrying ability of the energy transport system. In terms of electric energy this is typically expressed in MegaWatts (MW) or MegaVolt-Amperes (MVA) of generation, transmission, distribution or other electrical equipment. In terms of gas transport it is expressed in Million Cubic Feet per Day (mmcf/d) or decatherms of energy.

"Decatherm" is a gas energy measurement of heat, equivalent to 1,000,000 British Thermal Units (BTU).

"Delaware Department of Transportation (DelDOT)" is the State agency responsible for transportation infrastructure including highways, related property rights and public transit systems.

"Delaware Economic Development Office (DEDO)" is the State agency responsible for planning and encouraging economic growth and development.

"Delaware Electric Cooperative (DEC)" is a cooperative public utility that provides electric service to customers throughout Kent and Sussex Counties, Delaware.

"Delaware Public Service Commission (PSC)" is the State agency responsible for public utility regulation including retail pricing and service levels.

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[45] Glossary term definitions are based on various internet site material including Dept. of Energy (Consumer Energy Information, Distributed Energy Resources), and NERC (Glossary of Terms).

"Delmarva Power & Light Co. (DP&L, a.k.a Conectiv)" is an investor owned public utility that provides electric and natural gas services throughout New Castle County and electric service in throughout the remainder of the Delmarva Peninsula.

"Demand Response" means all activities or programs undertaken by a public utility or its customers to influence the amount or timing of energy use.

"Department of Natural Resources and Environmental Control (DNREC)" is the State agency responsible for managing and conserving the natural resources of Delaware via rules, regulations and enforcement practices.

"Distributed Generation" means electric generation that is typically anywhere from 1 to 100 MegaWatt (MW)size generating units, generally located throughout the service area, and usually installed for specific customers emergency backup or load control (peak shaving).

"Distribution Facilities" means electric facilities located in Delaware that are owned by a public utility that operate at voltages of 34,500 volts or below and that are used to deliver electricity to customers, up through and including the point of physical connection with electric facilities owned by the customer.

"Energy" as used in this report broadly includes electric, natural gas, propane, oil, coal, nuclear, or renewables (biomass, wind, photovoltaic) that provide usable power to consumers, usually in the form of heat or electricity.

"Energy Planning and Management Commission (EPMC)" means the proposed multi-State Commission charged with energy oversight on the Delmarva Peninsula.

"Federal Energy Regulatory Commission (FERC)" means the Federal agency under the Department of Energy, that regulates the interstate transmission of natural gas, oil and electricity and is responsible for licensing and inspecting hydroelectric projects.

"Federal Natural Gas Act" means the Federal legislation that regulates gas utilities and, for purposes of this report, provides and eminent domain right for facility siting and expansion.

"Generation (Electric)" means the process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

"Integrated Resource Planning (IRP)" means a planning process that provides for the lowest cost energy investment options that are consistent with society and governmental requirements (typically used in the electric industry prior to restructuring and the deregulation of generation).

"Locational Marginal Pricing (LMP)" means the pricing mechanism that is currently used by PJM for electrical energy purchase and sale between generators and load serving entities or wholesale customers.

"Load Serving Entity (LSE)" means a public utility owning and/or operating transmission and/or distribution facilities in Delaware.

"Mid Atlantic Area Council (MAAC)"means a regional council of the North American Electric Reliability Council ("NERC"), that is responsible for Mid Atlantic operational policies and reliability planning standards applicable to PJM and local electric distribution company members.

"Mid-Atlantic Conference of Regulatory Utility Commissioners (MACRUC)" means a regional subset of the NARUC organization that provides regional direction on regulatory issues.

"MegaVolt Ampere (MVA)" means a unit of apparent power, equal to 1,000,000 volt-amperes; the mathematical product of the volts and amperes in an electrical circuit.

"MegaWatt Hour (MWhr)" means a unit or measure of electricity supply or consumption of 1,000,000 Watts over the period of one hour; equivalent to 3,412,000 Btu.

"MegaWatt (MW)" means a standard unit of electrical power equal to one million watts, or to the energy consumption at a rate of 1,000,000 Joules per second.

"Merchant Transmission" is the commercial transmission investments made in response to market-based incentives. The return on investment depends on a combination of sales of transmission rights or profits from locational arbitrage of energy prices. The investment does not add to a regulated rate base or qualify for a regulatory recovery mechanism. The full market risk and reward accrue to the transmission investors.

"Million Cubic Feet per Day (mmcf/d)" means a million units of volume equal to 1 cubic foot at a pressure base of 14.73 pounds standard per square inch absolute and a temperature base of 60 degrees Fahrenheit, transported per day.

"Multi-State Energy Commission (MSEC)" means a multi-State regional entity, legislated into existence by a joint State resolution, and charged with planning, developing, managing and securing the energy needs for the regional area at the lowest cost consistent with society and governmental requirements.

"National Association of Regulatory Utility Commissioners (NARUC)" means a national nonprofit organization of State regulatory agencies, who's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation.

"North American Electric Reliability Council ('NERC')" means a national nonprofit organization responsible for operational policies and reliability planning standards applicable to national system operations and electric distribution companies, or their successor organizations.

"Office of State Planning Coordination (OSPC)" is a State agency responsible for the continuous improvement of the coordination and effectiveness of land use decisions made by State, county, and municipal governments.

"Old Dominion Electric Cooperative (ODEC, aka Old Dominion)" is a cooperative energy utility that provides reliable, safe and economical wholesale electric power for member cooperatives.

"PJM Interconnection, L.L.C. ('PJM')" means the independent system operator that is responsible for mid-Atlantic region wholesale energy markets and the interstate transmission of energy, or it's successor organization.

"Potomac Electric Power Company (PEPCO)" is an investor owned public utility, recently merged with Conectiv, that provides electric service in Washington DC and the surrounding area.

"Reliability Standards" as used in this report means the acceptable level of performance of the electric system when meeting NERC and MAAC operating criteria.

"Renewable Energy" means energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource.

"Standard Market Design (SMD)" is the proposed FERC rule making (NOPR) designed to stimulate energy markets and provide a more uniform, nondiscriminatory approach to managing energy systems.

"Transmission Facilities" means electric facilities located in Delaware and owned by a public utility that operate at voltages above 34,500 volts and that are used to transmit and deliver electricity to customers (including any customers taking electric service under interruptible rate schedules as of December 31, 1998) up through and including the point of physical connection with electric facilities owned by the customer.

"Transmission Owner (TO)" means the utility, merchant company or group of utilities that actually owns the transmission assets, regardless of who controls or operates the facilities.

"Transport Capacity" means the capacity available to transport the various forms of energy.

Attachment C
PJM DELMARVA PENINSULA CONGESTION ANALYSIS

DRAFT

Congestion Analysis of the Delmarva Peninsula

Calculation Methodology

Data Used

The congestion cost calculation and characterization are explained below. Most of the information is available from the PJM website:

Hourly Locational Marginal Price (LMP) Data – These data provide the marginal cost of electricity at over 2,000 points throughout the PJM network; some at specific generation, delivery, or load serving points, others as aggregate prices by zone or other groupings. 288 of these points are in the DPL (Delmarva) zone, and were the focus of this study. Real time LMP's were chosen as the prices for congestion calculation as these are the prices paid by load based on actual operations. Also, the constraint and outage information used in the study matches with real time data. The period of analysis is from August 1, 1999 (the first day of full PJM monitoring of the Delmarva network) to August 11, 2002 (most recent data available at study start). A total of 26,568 hours were analyzed.

Hourly Real Time Constraints – A list of transmission constraints is published by PJM for the entire region. This list was examined to include only constraints that are physically situated in the Delmarva zone. Constraints outside this zone (e.g. the PJM East Interface or the Trainer – Delco tap 230 kV line under the Red Lion – Hope Creek 500 kV line contingency) were excluded from the analysis. A total of 179 different events (monitored element / contingency combinations) met this criterion. Attachment A displays these events, the number of hours the event was limiting, and the percent of the total Delmarva constraint hours. The total constrained hours of 8,229 is more than the actual number of Delmarva constraint congested hours of 6,762 over the period because many hours had several simultaneous constraints (actually up to 5 simultaneous constraints as will be discussed later). For information, the constraint frequency by monitored element and contingency are listed as Attachment B and C respectively.

Hourly Delmarva Load – These data were obtained from the PJM website. Hourly Delmarva (DPL) zonal load was not readily available after May 31, 2002. From this date until August 11, 2002 DPL zonal load was assumed to be the average percent of PJM total load as recorded from August 1, 1999 to May 31, 2002 (4.29%).

Outages – PJM supplied a list of DPL zone outages for the study period. 540 outages were listed, ranging in duration from 30 minutes to 231 days.

Cost Calculation – The Zonal Approach

The simplest, top level approach for calculating congestion cost from LMP data is to use zonal cost data. The zonal LMP is calculated as the load weighted average of the nodal LMP's in the zone. The zonal congestion cost then is the difference between the hourly zonal LMP and a reference LMP, times the zonal load for that hour. Total period cost is the simple sum of the hourly congestion cost.

This calculation approach has several difficulties in general and for the purposes of this study. First, the selection of the reference LMP is not obvious. The ideal choice is the unconstrained marginal cost generator (lambda) for each hour, but this number was not routinely calculated or available. Other choices for the LMP reference (e.g. PJM average, Eastern Hub) are price affected by the universe of hourly constraints within and outside the DPL zone. Moreover, these reference points include the DPL zonal nodes within their calculation, further diminishing their value as a reference.

A correlation analysis was performed between the DPL zonal price and all other PJM nodal and zonal prices (that do not include DPL zone nodes in their calculation) for the period 4/1/1999 to 9/1/2002. The LMP point that correlated the best with the DPL zone (this will best isolate the DPL zone constraints) was the PECo zone. Using this reference, the total congestion cost for the DPL zone, summing only the hours when a constraint was occurring in the DPL zone, was found to be:

DPL Congestion Cost from Zonal (PECo vs DPL) Calculations in $ Millions

	8/1/99 to 12/31/99	2000	2001	1/1/02 to 8/11/02	Total
DPL Constrained Hours (All DPL events)	$8.70	$34.74	$65.28	$21.38	$130.09
DPL Constrained Hours (50 most frequent events)	$8.37	$32.70	$61.05	$20.06	$122.18

The total of $130 million in congestion cost should be viewed as an indicative but high estimate of DPL zonal congestion. The overestimation is believed to be caused by the effect of constraints outside of DPL increasing prices in the DPL zone. Examination of the cost impact of constraints outside the DPL zone occurring when no constraints were reported in DPL revealed that the PJM Eastern interface had the biggest congestion cost impact on the DPL zone (about a $6 average DPL zonal effect). Other historic data analysis revealed that the Eastern Interface constraint occurred concurrently with DPL constraints more often than any other (322 hours). The estimated impact of the Eastern Interface constraint on DPL zonal cost when DPL constraints were also in effect was $4.9 million. No other constraint outside of the DPL zone was estimated to affect the DPL zonal congestion by more than $60,000 over the study period. The resultant adjusted estimate of DPL constraint caused DPL zone congestion was:

Adjusted DPL Congestion Cost from Zonal (PECO vs DPL) Calculations in $ Millions

	Total
DPL Constrained Hours (All DPL events)	$125.19
DPL Constrained Hours (50 most frequent events)	$117.28

While congestion cost estimation with zonal prices is useful for estimating the total congestion cost, the zonal approach cannot assign costs to the limiting constraint, particularly when multiple constraints are occurring each hour. For the 6,762 hours when Delmarva constraints were in effect during the study period there was a maximum of 5 and an average of 1.2 simultaneous constraints every hour.

Cost Calculation Using Shadow Prices

Congestion cost calculation for each constraint requires the use of shadow prices for each constraint. The shadow price is the incremental value of relieving the constraint. A high shadow price indicates that the generation redispatch options to relieve a constraint are ineffective and/or expensive in relieving the constraint. A low shadow price indicates the constraint has a relatively close-by and/or inexpensive means of relief.

The nodal LMP is determined from the constraint shadow price by including the relative effect of the constraint on the load at that location. This relative effect is the distribution factor (also known as shift factor, generation shift factor, or DFAX) of a MW change at the constraint on the node in question. Nodes "close" to the constraint will have large distribution factors, and thus a large (or small) LMP indicative of the relative impact of a MW change to relieving the constraint. Nodes relative to a constrained "closed" interface such as the DPL interface will have a distribution factor of one or zero; a MW change on the higher price side of the closed constraint has a one-to-one relief effect. A MW change on the low price side will have no effect on the constraint. "Open" interfaces or constraints surrounded by parallel paths will have non-unity distribution factors.

If shadow prices are known, the cost of each constraint is calculated by the product of the shadow price and the load affected for each constraint. Multiple constraints are handled by the sum of the (shadow price) x (load affected) for all constraints.

Shadow prices (and the loads and distribution factors) are a byproduct of the on-line real time dispatch and LMP calculation. Unfortunately shadow prices were not calculated or saved during the course of market operations and thus were not available for this study.

Shadow Price Approximation

The Phase 1 study used the data available to approximate the shadow prices, then calculated the cost of each constraint for each constrained hour. Attachment D provides a derivation of the shadow price approximation. The key concept, shown in Attachment D, equation 2 is that the shadow price can be approximated by:

$$\text{Shadow Price} = \frac{\text{LMP difference across the constraint}}{\text{Effect of generation changes on the constraint}}$$

The numerator of the above equation is available from historic data.

The denominator is the distribution factor difference from redispatched generators to the load for the "from" and "to" sides of the constraint, calculated from a power flow model representing the network conditions (including transmission outages) for each constrained hour. The denominator will be called the "constraint effect distribution factor" in the balance of this report.

The congestion cost for a given constraint at an hour in question is the shadow price times the load affected. The load affected is calculated from the distribution factor of the DPL zonal load for a shift in generation using the same power flow model used to calculate the denominator above. This is Stated more formally in Attachment D, Equation 3.

Details of the calculation are included in attachment D. The important assumptions and implications of the calculation methodology were:

- The approach assumes that simultaneous constraints have an independent effect on locational prices. That is, the effect of one constraint on LMP's will be much larger than the effect of other constraints. The careful selection of LMP points "close" to the constraint from and to nodes reduces the effect of simultaneous constraints as much as possible.

- The distribution factor calculation for the shadow price calculation and load affected must reflect the network topology condition at each hour. In essence, the power flow network topology (including transmission outages) needs to be reproduced for all of the 6,762 constrained hours – an impossible task given the time and accuracy requirements of the study. Due to the time and labor intensive nature of this calculation several simplifying assumptions were made:

    § Only the most frequently occurring 50 constraint events were analyzed. This selection represents over 85% of the constrained hours. The constraints ignored due to this assumption occurred at most 30 hours out of the 26,568 study hours. Considering the events individually this resulted in the analysis of 7,089 individual constrained hours.

- § Due to the processing time required to include the effect of outages, and the desire to capture significant congestion causing events, it was decided to only analyze the effect of outages of one day duration or longer. 212 outages met this criterion. The 328 ignored outages represented less than 4% of the total outage hours during the study period. The maximum number of outages during any constrained hour was 12 with an average of almost 4 outages per hour. The combination of outages and the 50 most frequently occurring constraints led to 337 distribution factor calculations. (In essence 337 power flow snapshots were used to represent the network conditions during the 6,572 DPL constrained hours)

- § A single power flow case (the latest RTEP power flow case representing peak load conditions) was used to calculate distribution factors. In reality, network changes (primarily voltage upgrades) occurred in the Delmarva Peninsula during the 1999 to 2002 period. Precise distribution factor calculation would utilize power flow cases with topology in place that matched the hour, outages in place, and limiting constraints.

- For load and constraint effect distribution factor calculations it was assumed that all Delmarva load incrementally changes in proportion to the load represented in the power flow case. That is, changes in load occur pro rata to existing load.

- For constraint effect distribution factor calculation it was assumed that the generators that react to an incremental load change were all generators in PJM (whether on or off) in proportion to the relative generation available as modeled in the RTEP power flow case. In reality, each hour will have a different stack of generation that will serve an incremental load change, as determined by the hourly unit commitment and bid order. Even if these data were available, such hour-by-hour analysis would be far too time consuming for the purposes of this study.

- LMP and distribution factor calculation points were chosen as close as possible to the constraint "to" and "from" nodes. In most instances the selection of these points was obvious from the node names. When the selection was not obvious, the LMP record was examined to match the constrained hour with the highest and lowest LMP's during the constrained hour.

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Attachment A(PJM Congestion Report)
Congestion Causing Events in the Delmarva Peninsula
August 1, 1999 to August 11, 2002

	Event	Hours	% of Hours	Cum %
1	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 138 KV NEWCHURC-PINEYGRO 13764	1428	17%	17%
2	69 KV HALLWOOD-OAKHALL 6790-1 FLO 69 KV OAKHALL-TASLEY 6778	954	12%	29%
3	69 KV OAKHALL-TASLEY 6778 FLO 69 KV HALLWOOD-OAKHALL 6790-1	534	6%	35%
4	INTERFACE DPLSOUTH FLO Actual	484	6%	41%
5	69 KV EASTON-TRAPPETP 6716-1 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER	281	3%	45%
6	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV DOVERTAP-SHARRING 13704	243	3%	48%
7	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 69 KV KINGSCRK-LORETTO 6703	201	2%	50%
8	CHURCH 138 KV CHURCH AT2 XFORMER FLO 230 KV CEDARCRE-REDLION 23030	181	2%	52%
9	INDIANRI230 KV INDIANRI AT-20 XFORMER FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	178	2%	54%
10	69 KV EASTON-TRAPPETP 6716-1 FLO 230 KV INDIANRI-MILFORD 23069	115	1%	56%
11	69 KV MTHERMON-NSALISBU 6726 FLO 138 KV LORETTO-VIENNA 13780	113	1%	57%
12	69 KV CENTREVI-WYEMILLS 6710-4 FLO 138 KV CHURCH-STEELE 13701	106	1%	59%
13	KEENEY 230 KV KEENEY AT20 XFORMER FLO HARMONY 230 KV HARMONY AT20 XFORMER	106	1%	60%
14	KEENEY 500 KV KEENEY AT51 XFORMER FLO REDLION 500 KV REDLION AT50 XFORMER	100	1%	61%
15	138 KV LORETTO-VIENNA 13780 FLO Actual	98	1%	62%
16	230 KV EDGEMOOR-HARMONY 23012 FLO 500 KV HOPECREE-REDLION 5015	95	1%	63%
17	69 KV KINGSCRK-LORETTO 6703 FLO Actual	95	1%	65%
18	69 KV TALBOT-TRAPPETP 6716-2 FLO 230 KV INDIANRI-MILFORD 23069	93	1%	66%
19	138 KV MILFORD-SHARRING 13774 FLO 230 KV INDIANRI-MILFORD 23069	92	1%	67%
20	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV CHESWOLD-DOVERTAP 13775	91	1%	68%
21	69 KV MTHERMON-NSALISBU 6726 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	88	1%	69%

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Attachment A(PJM Congestion Report)
(Continued)

	Event	Hours	% of Hours	Cum %
22	KEENEY 500 KV KEENEY AT50 XFORMER FLO REDLION 500 KV REDLION AT50 XFORMER	87	1%	70%
23	69 KV VIENNA-VIENNALO 6702-2 FLO 138 KV CHURCH-STEELE 13701	83	1%	71%
24	69 KV BRIDGEVI-GREENWD 6738-1 FLO 230 KV INDIANRI-MILFORD 23069	78	1%	72%
25	KEENEY 500 KV KEENEY AT50 XFORMER FLO 500 KV KEENEY-REDLION 5036	73	1%	73%
26	69 KV TALBOT-TRAPPETP 6716-2 FLO VIENNA 230 KV VIENNA AT20 TRANSFORMER	71	1%	74%
27	69 KV OAKHALL-POCOMOKE 6787 FLO 138 KV NEWCHURC-PINEYGRO 13764	63	1%	75%
28	69 KV GREENWD-SHARRING 6738-2 FLO 230 KV INDIANRI-MILFORD 23069 138 KV NSEAFORD-SHARRING 13771	61	1%	75%
29	69 KV GREENWD-SHARRING 6738-2 FLO 230 KV INDIANRI-MILFORD 23069	57	1%	76%
30	69 KV CRISFIE-KINGSTON 6723-3 FLO 69 KV KINGSCRK-LORETTO 6703	54	1%	77%
31	KEENEY 500 KV KEENEY AT51 XFORMER FLO KEENEY 500 KV KEENEY AT50 XFORMER	52	1%	77%
32	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 69 KV HARRTN-SHARRING 6739	49	1%	78%
33	69 KV OAKHALL-TASLEY 6778 FLO Actual	48	1%	78%
34	69 KV CHURCH-NEWMERED 6704-1 FLO 230 KV CEDARCRE-REDLION 23030	47	1%	79%
35	PINEYGRO138 KV PINEYGRO AT1 XFORMER FLO 138 KV NEWCHURC-PINEYGRO 13764	47	1%	80%
36	138 KV NELSON-VIENNA 13707 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER	46	1%	80%
37	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO STEELE 230 KV STEELE AT20 XFORMER	44	1%	81%
38	KEENEY 500 KV KEENEY AT51 XFORMER FLO 500 KV KEENEY-REDLION 5036	43	1%	81%
39	69 KV EASTON-TRAPPETP 6716-1 FLO VIENNA 230 KV VIENNA AT20 TRANSFORMER	42	1%	82%
40	69 KV KINGSCRK-LORETTO 6703 FLO 138 KV LORETTO-PINEYGRO 13777	42	1%	82%
41	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO CHURCH 138 KV CHURCH AT2 XFORMER	42	1%	83%
42	69 KV CENTREVI-WYEMILLS 6710-4 FLO 138 KV HILLSBRO-STEELE 13761 & 138 KV CHURCH-STEELE 13701	41	0%	83%
43	69 KV CHURCH-IBCORN 6710-1 FLO 138 KV CHURCH-STEELE 13701	41	0%	84%

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Attachment A(PJM Congestion Report)
(Continued)

	Event	Hours	% of Hours	Cum %
44	69 KV MTOLIVE-PINEYGRO 6729-1 FLO OAKHALL 138 KV OAKHALL AT1 XFORMER	41	0%	84%
45	230 KV EDGEMOOR-HARMONY 23012 FLO 500 KV KEENEY-PEACHBOT 5014	38	0%	85%
46	69 KV KINGSCRK-LORETTO 6703 FLO 69 KV MTOLIVE-PINEYGRO 6729-1	38	0%	85%
47	69 KV GREENWD-SHARRING 6738-2 FLO NSEAFORD138 KV NSEAFORD AT-1 XFORMER	36	0%	86%
48	138 KV CECIL-GLASGOW 13810 FLO 500 KV HOPECREE-REDLION 5015	34	0%	86%
49	69 KV BRIDGEVI-GREENWD 6738-1 FLO 230 KV INDIANRI-MILFORD 23069 138 KV NSEAFORD-SHARRING 13771	31	0%	86%
50	69 KV CENTREVI-WYEMILLS 6710-4 FLO STEELE 230 KV STEELE AT20 XFORMER	30	0%	87%
51	VIENNA 230 KV VIENNA 230 KV AT20 XFORMER FLO 230 KV INDIANRI-MILFORD 23069	30	0%	87%
52	69 KV FRUITLAN-NSALISBU 6701 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	28	0%	87%
53	69 KV CHURCH-IBCORN 6710-1 FLO WYEMILLS138KV WYEMILLS AT-1 XFORMER & WYEMILLS138KV WYEMILLS AT-2 XFORMER	27	0%	88%
54	69 KV HALLWOOD-OAKHALL 6790-1 FLO Actual	27	0%	88%
55	138 KV BASINRD-CHURCTAP FLO KEENEY 230 KV KEENEY AT20 XFORMER	25	0%	88%
56	69 KV VIENNA-VIENNALO 6702-2 FLO 69 KV EASTON-EASTONTP 6707-1	25	0%	89%
57	138 KV INDIANRI-NSEAFORD 13766 FLO 230 KV INDIANRI-MILFORD 23069	23	0%	89%
58	69 KV OAKHALL-POCOMOKE 6787 FLO 69 KV MTOLIVE-PINEYGRO 6729-1	22	0%	89%
59	138 KV CHR138-EDGEMOOR 13805 FLO 500 KV HOPECREE-REDLION 5015	19	0%	89%
60	69 KV DUPSEAFD-LAURELDP 6736 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER & 230 KV INDIANRI-MILFORD 23069	19	0%	90%
61	CHURCH 138 KV CHURCH AT2 XFORMER FLO MILFORD 230 KV MILFORD AT20 XFORMER	19	0%	90%
62	69 KV MTHERMON-NSALISBU 6726 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER	18	0%	90%
63	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV DOVERTAP-SHARRING 13704 138 KV CEDARCRE-CLAYTON 13832	18	0%	90%

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Attachment A(PJM Congestion Report)
(Continued)

	Event	Hours	% of Hours	Cum %
64	REDLION 230 KV REDLION AT20 XFORMER FLO HARMONY 230 KV HARMONY AT20 XFORMER	18	0%	91%
65	138 KV LORETTO-PINEYGRO 13777 FLO 138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	17	0%	91%
66	CECIL 230 KV CECIL T3 XFORMER FLO KEENEY 230 KV KEENEY AT20 XFORMER	17	0%	91%
67	69 KV DUPSEAFD-LAURELDP 6736 FLO 230 KV INDIANRI-MILFORD 23069	16	0%	91%
68	69 KV FRUITLAN-NSALISBU 6701 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002 138 KV LORETTO-VIENNA 13780	16	0%	91%
69	69 KV MARDELA-VIENNA 6708-3 FLO LORETTO 138 KV LORETTO AT1 XFORMER	16	0%	92%
70	INDIANRI230 KV INDIANRI AT-20 XFORMER FLO 230 KV INDIANRI-MILFORD 23069	16	0%	92%
71	230 KV CHICHEST-CLAYMONT 220-39 FLO 230 KV CHICHEST-EDGEMOOR 220-43	15	0%	92%
72	69 KV TALBOT-TANYARD 6716-3 FLO VIENNA 230 KV VIENNA AT20 TRANSFORMER	15	0%	92%
73	KEENEY 500 KV KEENEY AT50 XFORMER FLO KEENEY 500 KV KEENEY AT51 XFORMER	15	0%	92%
74	138 KV CLAYTON-JONES 13770-2 FLO 230 KV CEDARCRE-MILFORD 23031	14	0%	92%
75	138 KV GLASGOW-MTPLEASN 13808 FLO 230 KV CEDARCRE-REDLION 23030	14	0%	93%
76	230 KV CHICHEST-EDGEMOOR 220-43 FLO 230 KV CLAYMONT-EDGEMOOR 23015	14	0%	93%
77	69 KV BASIN-BEAR DPL 6816 FLO REDLION 230 KV REDLION AT20 XFORMER	14	0%	93%
78	69 KV FRUITLAN-NSALISBU 6701 FLO 138 KV LORETTO-VIENNA 13780	14	0%	93%
79	69 KV KINGSCRK-LORETTO 6703 FLO OAKHALL 138 KV OAKHALL AT1 XFORMER	14	0%	93%
80	STEELE 230 KV STEELE AT20 XFORMER FLO Actual	14	0%	93%
81	WYEMILLS138KV WYEMILLS AT-2 XFORMER FLO 69 KV TALBOT-TRAPPETP 6716-2	14	0%	94%
82	230 KV INDIANRI-MILFORD 23069 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	13	0%	94%
83	69 KV KINGSCRK-LORETTO 6703 FLO 138 KV NEWCHURC-PINEYGRO 13764	13	0%	94%
84	69 KV STOCKTON-WATTSVIL 6712-2 FLO 138 KV NEWCHURC-OAKHALL 13765	13	0%	94%

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Attachment A(PJM Congestion Report)
(Continued)

	Event	Hours	% of Hours	Cum %
85	69 KV TODD-VIENNALO 6702-1 FLO 69 KV LONGWOOD-WYEMILLS 6707-3	13	0%	94%
86	69 KV PRESTON-TODD 6716-5 FLO VIENNA 230 KV VIENNA AT20 TRANSFORMER	12	0%	94%
87	138 KV CEDARCRE-CLAYTON 13832 FLO Actual	12	0%	95%
88	138 KV GLASGOW-MTPLEASN 13808 FLO STEELE 230 KV STEELE AT20 XFORMER	12	0%	95%
89	69 KV CENTREVI-WYEMILLS 6710-4 FLO Actual	12	0%	95%
90	69 KV CENTREVI-WYEMILLS 6710-4 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	12	0%	95%
91	69 KV OAKHALL-TASLEY 6778 FLO 69 KV GREENBUS-TASLEY 6709-3	12	0%	95%
92	69 KV KINGSCRK-LORETTO 6703 FLO 138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	11	0%	95%
93	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 69 KV OAKHALL-POCOMOKE 6787	11	0%	95%
94	69 KV TALBOT-TRAPPETP 6716-2 FLO 230 KV MILFORD-STEELE 23076	11	0%	96%
95	69 KV DUPSEAFD-LAURELDP 6736 FLO 230 KV STEELE-VIENA 23085	10	0%	96%
96	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	10	0%	96%
97	69 KV NSEAFORD-PINE ST 6752-2 FLO 138 KV INDIANRI-NELSON 13703	10	0%	96%
98	INDIANRI230 KV INDIANRI AT-20 XFORMER FLO INDIANRI14 KV INDIANRI UNIT01 GEN UNIT	10	0%	96%
99	KEENEY 500 KV KEENEY AT51 XFORMER FLO REDLION 500 KV REDLION AT50 XFORMER KEENEY 500 KV KEENEY AT50 XFORMER	10	0%	96%
100	69 KV CHURCH-IBCORN 6710-1 FLO 138 KV EASTON-STEELE 13712 & EASTON 138 KV EASTON AT-1 XFORMER	9	0%	96%
101	69 KV NSEAFORD-PINE ST 6752-2 FLO VIENNA 230 KV VIENNA AT20 TRANSFORMER	9	0%	96%
102	230 KV CLAYMONT-EDGEMOOR 23015 FLO 230 KV CHICHEST-EDGEMOOR 220-43	8	0%	97%
103	69 KV CHURCH-IBCORN 6710-1 FLO STEELE 230 KV STEELE AT20 XFORMER	8	0%	97%
104	69 KV CHURCH-NEWMERED 6704-1 FLO 230 KV KEENEY-STEELE 23009 & 230 KV MILFORD-STEELE 23076	8	0%	97%
105	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 230 KV CEDARCRE-REDLION 23030	8	0%	97%

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Attachment A(PJM Congestion Report)
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	Event	Hours	% of Hours	Cum %
106	INDIANRI230 KV INDIANRI AT-20 XFORMER FLO MILFORD 230 KV MILFORD AT20 XFORMER	8	0%	97%
107	REDLION 500 KV REDLION AT50 XFORMER FLO 500 KV KEENEY-REDLION 5036	8	0%	97%
108	138 KV MTPLEASN-TOWNSEND 13808 FLO STEELE 230 KV STEELE AT20 XFORMER	7	0%	97%
109	138 KV NEWCHURC-PINEYGRO 13764 FLO 69 KV KINGSCRK-LORETTO 6703	7	0%	97%
110	69 KV BRIDGEVI-TAYLOR 6737-1 FLO 230 KV INDIANRI-MILFORD 23069	7	0%	97%
111	69 KV CHESWOLD-KENT 6768 FLO 138 KV DOVERTAP-SHARRING 13704 138 KV CEDARCRE-CLAYTON 13832	7	0%	97%
112	69 KV FRUITLAN-NSALISBU 6701 FLO LORETTO 138 KV LORETTO AT1 XFORMER	7	0%	97%
113	69 KV OAKHALL-TASLEY 6778 FLO 69 KV OAKHALL-WATTSVIL 6717	7	0%	97%
114	69 KV PRESTON-TANYARD 6716-4 FLO 230 KV INDIANRI-MILFORD 23069	7	0%	98%
115	CHURCH 138 KV CHURCH AT2 XFORMER FLO MILFORD 230 KV MILFORD AT20 XFORMER 138 KV CEDARCRE-CLAYTON 13832	7	0%	98%
116	138 KV BASINRD-CHURCTAP FLO 230 KV HARMONY-KEENEY	6	0%	98%
117	138 KV CHR138-EDGEMOOR 13805 FLO REDLION 500 KV REDLION AT50 XFORMER	6	0%	98%
118	69 KV OAKHALL-POCOMOKE 6787 FLO LORETTO 138 KV LORETTO AT1 XFORMER	6	0%	98%
119	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV DOVERTAP-SHARRING 13704 138 KV CLAYTON-JONES 13770-2	6	0%	98%
120	138 KV MILFORD-SHARRING 13774 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER	5	0%	98%
121	230 KV CEDARCRE-REDLION 23030 FLO 230 KV KEENEY-STEELE 23001	5	0%	98%
122	500 KV KEENEY-PEACHBOT 5014 FLO Actual	5	0%	98%
123	69 KV FRUITLAN-NSALISBU 6701 FLO 138 KV NEWCHURC-OAKHALL 13765	5	0%	98%
124	69 KV HEBRON-NSALISBU 6708-1 FLO LORETTO 138 KV LORETTO AT1 XFORMER	5	0%	98%
125	69 KV OAKHALL-POCOMOKE 6787 FLO OAKHALL 138 KV OAKHALL AT2 XFORMER	5	0%	98%
126	69 KV VIENNA-VIENNALO 6702-2 FLO 138 KV EASTON-STEELE 13712 & EASTON 138 KV EASTON AT-1 XFORMER	5	0%	98%
127	INDIANRI230 KV INDIANRI AT-20 XFORMER FLO Actual	5	0%	98%

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Attachment A(PJM Congestion Report)
(Continued)

	Event	Hours	% of Hours	Cum %
128	KEENEY 500 KV KEENEY AT50 XFORMER FLO KEENEY 500 KV KEENEY AT51 XFORMER REDLION 500 KV REDLION AT50 XFORMER	5	0%	99%
129	WYEMILLS138KV WYEMILLS AT-2 XFORMER FLO EASTON 138 KV EASTON AT-1 XFORMER	5	0%	99%
130	138 KV INDIANRI-NELSON 13703 FLO PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	4	0%	99%
131	138 KV CLAYTON-JONES 13770-2 FLO MILFORD 230 KV MILFORD AT20 XFORMER	4	0%	99%
132	138 KV EASTON-STEELE 13712 FLO Actual	4	0%	99%
133	138 KV LORETTO-PINEYGRO 13777 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER & 230 KV INDIANRI-MILFORD 23069	4	0%	99%
134	230 KV CHICHEST-CLAYMONT 220-39 FLO 230 KV CLAYMONT-EDGEMOOR 23015	4	0%	99%
135	69 KV KENNEY-STOCKTON 6712-1 FLO 138 KV NEWCHURC-PINEYGRO 13764	4	0%	99%
136	69 KV KINGSCRK-LORETTO 6703 FLO 69 KV CRISFIE-KINGSTON 6725-3	4	0%	99%
137	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 138 KV NEWCHURC-PINEYGRO 13764 138 KV COSTEN-KINGSCRK 13714-2	4	0%	99%
138	69 KV OAKHALL-POCOMOKE 6787 FLO 138 KV NEWCHURC-OAKHALL 13765	4	0%	99%
139	69 KV OAKHALL-POCOMOKE 6787 FLO 138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	4	0%	99%
140	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV DOVERTAP-SHARRING 13704 138 KV CHESWOLD-JONES 13770-1	4	0%	99%
141	REDLION 230 KV REDLION AT20 XFORMER FLO 230 KV HARMONY-KEENEY 23013	4	0%	99%
142	138 KV BASINRD-KIAMENSI 13813 FLO HARMONY 230 KV HARMONY AT20 XFORMER	3	0%	99%
143	69 KV FRUITLAN-NSALISBU 6701 FLO 138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	3	0%	99%
144	69 KV MTOLIVE-PINEYGRO 6729-1 FLO 138 KV NEWCHURC-OAKHALL 13765	3	0%	99%
145	69 KV TALBOT-TANYARD 6716-3 FLO 230 KV MILFORD-STEELE 23076	3	0%	99%
146	CECIL 230 KV CECIL T3 XFORMER FLO KEENEY 500 KV KEENEY AT50 XFORMER	3	0%	99%

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Attachment A (PJM Congestion Report)
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	Event	Hours	% of Hours	Cum %
147	NSEAFORD138 KV NSEAFORD AT-1 XFORMER FLO SHARRING138 KV SHARRING AT-1 XFORMER	3	0%	99%
148	VIENNA 230 KV VIENNA 230 KV AT20 XFORMER FLO 230 KV MILFORD-STEELE 23076	3	0%	99%
149	138 KV CHESWOLD-DOVERTAP 13775 FLO 138 KV DOVERTAP-SHARRING 13704	2	0%	99%
150	138 KV CLAYTON-JONES 13770-2 FLO 230 KV MILFORD-STEELE 23076	2	0%	99%
151	230 KV EDGEMOOR-HARMONY 23012 FLO 500 KV KEENEY-PEACHBOT 5014 500 KV HOPECREE-REDLION 5015	2	0%	99%
152	500 KV HOPECREE-REDLION 5015 FLO Actual	2	0%	100%
153	500 KV KEENEY-PEACHBOT 5014 FLO 500 KV ALBURTIS-BRANCHBU 5016	2	0%	100%
154	69 KV BRIDGEVI-GREENWD 6738-1 FLO 138 KV NSEAFORD-SHARRING 13771	2	0%	100%
155	69 KV CHURCH-IBCORN 6710-1 FLO 138 KV HILLSBRO-STEELE 13761 & 138 KV HILLSBRO-WYEMILLS 13788	2	0%	100%
156	69 KV EASTON-EMUNI 6772 FLO WYEMILLS138KV WYEMILLS AT-1 XFORMER	2	0%	100%
157	69 KV FRUITLAN-LORETTO 6711 FLO LORETTO 138 KV LORETTO AT1 XFORMER	2	0%	100%
158	69 KV FRUITLAN-NSALISBU 6701 FLO 138 KV LORETTO-VIENNA 13780 230 KV INDIANRI-PINEYGRO 23002	2	0%	100%
159	69 KV MTOLIVE-PINEYGRO 6729-1 FLO PINEYGRO138 KV PINEYGRO AT1 XFORMER	2	0%	100%
160	69 KV OAKHALL-POCOMOKE 6787 FLO OAKHALL 138 KV OAKHALL AT1 XFORMER	2	0%	100%
161	69 KV STOCKTON-WATTSVIL 6712-2 FLO 138 KV NEWCHURC-PINEYGRO 13764	2	0%	100%
162	69 KV TALBOT-TRAPPETP 6716-2 FLO 230 KV STEELE-VIENA 23085	2	0%	100%
163	69 KV VIENNA-VIENNALO 6702-2 FLO STEELE 230 KV STEELE AT20 XFORMER	2	0%	100%
164	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV CHESWOLD-DOVERTAP 13775 230 KV CEDARCRE-MILFORD 23031	2	0%	100%
165	CHESWOLD138 KV CHESWOLD AT1 XFORMER FLO 138 KV CEDARCRE-CLAYTON 13832 & 138 KV DOVERTAP-SHARRING 13704	2	0%	100%
166	CHURCH 138 KV CHURCH AT2 XFORMER FLO 138 KV HILLSBRO-STEELE 13761 & 138 KV HILLSBRO-WYEMILLS 13788	2	0%	100%
167	KEENEY 500 KV KEENEY AT50 XFORMER FLO REDLION 230 KV REDLION AT20 XFORMER	2	0%	100%

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	Event	Hours	% of Hours	Cum %
168	138 KV LORETTO-PINEYGRO 13777 FLO 230 KV INDIANRI-MILFORD 23069	1	0%	100%
169	138 KV LORETTO-PINEYGRO 13777 FLO INDIANRI230KV INDIANRI 232 CB	1	0%	100%
170	500 KV HOPECREE-REDLION 5015 FLO 230 KV CHAMBERS-CHURCHTO 2313	1	0%	100%
171	69 KV BRIDGEVI-GREENWD 6738-1 FLO INDIANRI230 KV INDIANRI AT-20 XFORMER	1	0%	100%
172	69 KV CHURCH-NEWMERED 6704-1 FLO 230 KV MILFORD-STEELE 23076	1	0%	100%
173	69 KV CHURCH-NEWMERED 6704-1 FLO CEDARCRE230 KV CEDARCRE AT20 XFORMER	1	0%	100%
174	69 KV GREENWD-SHARRING 6738-2 FLO 138 KV NSEAFORD-SHARRING 13771	1	0%	100%
175	69 KV OAKHALL-POCOMOKE 6787 FLO 69 KV FRUITLAN-NSALISBU 6701	1	0%	100%
176	69 KV TALBOT-TRAPPETP 6716-2 FLO 230 KV INDIANRI-MILFORD 23069 230 KV STEELE-VIENA 23085	1	0%	100%
177	69 KV TALBOT-TRAPPETP 6716-2 FLO 230 KV CEDARCRE-MILFORD 23031	1	0%	100%
178	EDGEMOOR230 KV EDGEMOOR AT20 XFORMER FLO 500 KV HOPECREE-REDLION 5015	1	0%	100%
179	FLO 69 KV OAKHALL-TASLEY 6778	0	0%	100%

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Attachment B(PJM Congestion Report)
Congestion Causing Transmission Facilities in the Delmarva Peninsula
August 1, 1999 to August 11, 2002

	Monitored Element	Hours	% of Hours	Cum %
1	69 KV MTOLIVE-PINEYGRO 6729-1	1700	21%	21%
2	69 KV HALLWOOD-OAKHALL 6790-1	981	12%	33%
3	69 KV OAKHALL-TASLEY 6778	601	7%	40%
4	CHESWOLD138 KV CHESWOLD AT1 XFORMER	509	6%	46%
5	INTERFACE DPLSOUTH	484	6%	52%
6	69 KV EASTON-TRAPPETP 6716-1	438	5%	57%
7	69 KV MTHERMON-NSALISBU 6726	219	3%	60%
8	69 KV KINGSCRK-LORETTO 6703	217	3%	63%
9	INDIANRI230 KV INDIANRI AT-20 XFORMER	217	3%	65%
10	CHURCH 138 KV CHURCH AT2 XFORMER	209	3%	68%
11	KEENEY 500 KV KEENEY AT51 XFORMER	205	2%	70%
12	69 KV CENTREVI-WYEMILLS 6710-4	201	2%	73%
13	KEENEY 500 KV KEENEY AT50 XFORMER	182	2%	75%
14	69 KV TALBOT-TRAPPETP 6716-2	179	2%	77%
15	69 KV GREENWD-SHARRING 6738-2	155	2%	79%
16	230 KV EDGEMOOR-HARMONY 23012	135	2%	81%
17	69 KV VIENNA-VIENNALO 6702-2	115	1%	82%
18	69 KV BRIDGEVI-GREENWD 6738-1	112	1%	83%
19	69 KV OAKHALL-POCOMOKE 6787	107	1%	85%
20	KEENEY 230 KV KEENEY AT20 XFORMER	106	1%	86%
21	138 KV LORETTO-VIENNA 13780	98	1%	87%
22	138 KV MILFORD-SHARRING 13774	97	1%	88%
23	69 KV CHURCH-IBCORN 6710-1	87	1%	89%
24	69 KV FRUITLAN-NSALISBU 6701	75	1%	90%
25	69 KV CHURCH-NEWMERED 6704-1	57	1%	91%
26	69 KV CRISFIE-KINGSTON 6723-3	54	1%	92%
27	PINEYGRO138 KV PINEYGRO AT1 XFORMER	47	1%	92%
28	138 KV NELSON-VIENNA 13707	46	1%	93%
29	69 KV DUPSEAFD-LAURELDP 6736	45	1%	93%
30	138 KV CECIL-GLASGOW 13810	34	0%	94%
31	VIENNA 230 KV VIENNA 230 KV AT20 XFORMER	33	0%	94%
32	138 KV BASINRD-CHURCTAP	31	0%	94%
33	138 KV GLASGOW-MTPLEASN 13808	26	0%	95%

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Attachment B(PJM Congestion Report)
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	Monitored Element	Hours	% of Hours	Cum %
34	138 KV CHR138-EDGEMOOR 13805	25	0%	95%
35	138 KV INDIANRI-NSEAFORD 13766	23	0%	95%
36	138 KV LORETTO-PINEYGRO 13777	23	0%	96%
37	REDLION 230 KV REDLION AT20 XFORMER	22	0%	96%
38	138 KV CLAYTON-JONES 13770-2	20	0%	96%
39	CECIL 230 KV CECIL T3 XFORMER	20	0%	96%
40	230 KV CHICHEST-CLAYMONT 220-39	19	0%	97%
41	69 KV NSEAFORD-PINE ST 6752-2	19	0%	97%
42	WYEMILLS138KV WYEMILLS AT-2 XFORMER	19	0%	97%
43	69 KV TALBOT-TANYARD 6716-3	18	0%	97%
44	69 KV MARDELA-VIENNA 6708-3	16	0%	98%
45	69 KV STOCKTON-WATTSVIL 6712-2	15	0%	98%
46	230 KV CHICHEST-EDGEMOOR 220-43	14	0%	98%
47	69 KV BASIN-BEAR DPL 6816	14	0%	98%
48	STEELE 230 KV STEELE AT20 XFORMER	14	0%	98%
49	230 KV INDIANRI-MILFORD 23069	13	0%	98%
50	69 KV TODD-VIENNALO 6702-1	13	0%	99%
51	69 KV PRESTON-TODD 6716-5	12	0%	99%
52	138 KV CEDARCRE-CLAYTON 13832	12	0%	99%
53	230 KV CLAYMONT-EDGEMOOR 23015	8	0%	99%
54	REDLION 500 KV REDLION AT50 XFORMER	8	0%	99%
55	138 KV MTPLEASN-TOWNSEND 13808	7	0%	99%
56	138 KV NEWCHURC-PINEYGRO 13764	7	0%	99%
57	500 KV KEENEY-PEACHBOT 5014	7	0%	99%
58	69 KV BRIDGEVI-TAYLOR 6737-1	7	0%	99%
59	69 KV CHESWOLD-KENT 6768	7	0%	99%
60	69 KV PRESTON-TANYARD 6716-4	7	0%	100%
61	230 KV CEDARCRE-REDLION 23030	5	0%	100%
62	69 KV HEBRON-NSALISBU 6708-1	5	0%	100%
63	138 KV INDIANRI-NELSON 13703	4	0%	100%
64	138 KV EASTON-STEELE 13712	4	0%	100%
65	69 KV KENNEY-STOCKTON 6712-1	4	0%	100%
66	138 KV BASINRD-KIAMENSI 13813	3	0%	100%
67	500 KV HOPECREE-REDLION 5015	3	0%	100%
68	NSEAFORD138 KV NSEAFORD AT-1 XFORMER	3	0%	100%
69	138 KV CHESWOLD-DOVERTAP 13775	2	0%	100%
70	69 KV EASTON-EMUNI 6772	2	0%	100%
71	69 KV FRUITLAN-LORETTO 6711	2	0%	100%
72	EDGEMOOR230 KV EDGEMOOR AT20 XFORMER	1	0%	100%

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Attachment C (PJM Congestion Report)
Congestion Causing Contingencies in the Delmarva Peninsula
August 1, 1999 to August 11, 2002

	Contingencies	Hours	% of Hours	Cum %
1	138 KV NEWCHURC-PINEYGRO 13764	1557	19%	19%
2	69 KV OAKHALL-TASLEY 6778	954	12%	31%
3	Actual	806	10%	40%
4	230 KV INDIANRI-MILFORD 23069	535	7%	47%
5	69 KV HALLWOOD-OAKHALL 6790-1	534	6%	53%
6	INDIANRI230 KV INDIANRI AT-20 XFORMER	333	4%	57%
7	PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002	323	4%	61%
8	69 KV KINGSCRK-LORETTO 6703	262	3%	64%
9	230 KV CEDARCRE-REDLION 23030	250	3%	67%
10	138 KV DOVERTAP-SHARRING 13704	245	3%	70%
11	138 KV CHURCH-STEELE 13701	230	3%	73%
12	REDLION 500 KV REDLION AT50 XFORMER	193	2%	76%
13	500 KV HOPECREE-REDLION 5015	149	2%	77%
14	VIENNA 230 KV VIENNA AT20 TRANSFORMER	149	2%	79%
15	138 KV LORETTO-VIENNA 13780	127	2%	81%
16	HARMONY 230 KV HARMONY AT20 XFORMER	127	2%	82%
17	500 KV KEENEY-REDLION 5036	124	2%	84%
18	STEELE 230 KV STEELE AT20 XFORMER	103	1%	85%
19	230 KV INDIANRI-MILFORD 23069 138 KV NSEAFORD-SHARRING 13771	92	1%	86%
20	138 KV CHESWOLD-DOVERTAP 13775	91	1%	87%
21	69 KV MTOLIVE-PINEYGRO 6729-1	60	1%	88%
22	OAKHALL 138 KV OAKHALL AT1 XFORMER	57	1%	89%
23	KEENEY 500 KV KEENEY AT50 XFORMER	55	1%	89%
24	69 KV HARRTN-SHARRING 6739	49	1%	90%
25	138 KV OAKHALL-PINEYGRO 13764 & OAKHALL 138 KV OAKHALL AT1 XFORMER	45	1%	91%
26	138 KV LORETTO-PINEYGRO 13777	42	1%	91%
27	CHURCH 138 KV CHURCH AT2 XFORMER	42	1%	92%
28	KEENEY 230 KV KEENEY AT20 XFORMER	42	1%	92%
29	138 KV HILLSBRO-STEELE 13761 & 138 KV CHURCH-STEELE 13701	41	0%	93%
30	500 KV KEENEY-PEACHBOT 5014	38	0%	93%
31	LORETTO 138 KV LORETTO AT1 XFORMER	36	0%	93%
32	NSEAFORD138 KV NSEAFORD AT-1 XFORMER	36	0%	94%
33	MILFORD 230 KV MILFORD AT20 XFORMER	31	0%	94%
34	WYEMILLS138KV WYEMILLS AT-1 XFORMER & WYEMILLS138KV WYEMILLS AT-2 XFORMER	27	0%	95%
35	138 KV DOVERTAP-SHARRING 13704 138 KV CEDARCRE-CLAYTON 13832	25	0%	95%

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Attachment C (PJM Congestion Report)
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	Contingencies	Hours	% of Hours	Cum %
36	138 KV NEWCHURC-OAKHALL 13765	25	0%	95%
37	69 KV EASTON-EASTONTP 6707-1	25	0%	96%
38	230 KV CHICHEST-EDGEMOOR 220-43	23	0%	96%
39	INDIANRI230 KV INDIANRI AT-20 XFORMER & 230 KV INDIANRI-MILFORD 23069	23	0%	96%
40	230 KV MILFORD-STEELE 23076	20	0%	96%
41	230 KV CLAYMONT-EDGEMOOR 23015	18	0%	97%
42	PINEYGRO230 KV PINEYGRO AT20 XFORMER	18	0%	97%
43	PINEYGRO230 KV PINEYGRO AT20 XFORMER 230 KV INDIANRI-PINEYGRO 23002 138 KV LORETTO-VIENNA 13780	16	0%	97%
44	REDLION 230 KV REDLION AT20 XFORMER	16	0%	97%
45	230 KV CEDARCRE-MILFORD 23031	15	0%	97%
46	KEENEY 500 KV KEENEY AT51 XFORMER	15	0%	98%
47	138 KV EASTON-STEELE 13712 & EASTON 138 KV EASTON AT-1 XFORMER	14	0%	98%
48	69 KV TALBOT-TRAPPETP 6716-2	14	0%	98%
49	69 KV LONGWOOD-WYEMILLS 6707-3	13	0%	98%
50	230 KV STEELE-VIENA 23085	12	0%	98%
51	69 KV GREENBUS-TASLEY 6709-3	12	0%	98%
52	69 KV OAKHALL-POCOMOKE 6787	11	0%	98%
53	138 KV INDIANRI-NELSON 13703	10	0%	99%
54	INDIANRI14 KV INDIANRI UNIT01 GEN UNIT	10	0%	99%
55	REDLION 500 KV REDLION AT50 XFORMER KEENEY 500 KV KEENEY AT50 XFORMER	10	0%	99%
56	230 KV KEENEY-STEELE 23009 & 230 KV MILFORD-STEELE 23076	8	0%	99%
57	69 KV OAKHALL-WATTSVIL 6717	7	0%	99%
58	MILFORD 230 KV MILFORD AT20 XFORMER 138 KV CEDARCRE-CLAYTON 13832	7	0%	99%
59	230 KV HARMONY-KEENEY	6	0%	99%
60	138 KV DOVERTAP-SHARRING 13704 138 KV CLAYTON-JONES 13770-2	6	0%	99%
61	230 KV KEENEY-STEELE 23001	5	0%	99%
62	EASTON 138 KV EASTON AT-1 XFORMER	5	0%	99%
63	KEENEY 500 KV KEENEY AT51 XFORMER REDLION 500 KV REDLION AT50 XFORMER	5	0%	99%
64	OAKHALL 138 KV OAKHALL AT2 XFORMER	5	0%	99%
65	230 KV HARMONY-KEENEY 23013	4	0%	100%
66	138 KV HILLSBRO-STEELE 13761 & 138 KV HILLSBRO-WYEMILLS 13788	4	0%	100%
67	69 KV CRISFIE-KINGSTON 6725-3	4	0%	100%
68	138 KV DOVERTAP-SHARRING 13704 138 KV CHESWOLD-JONES 13770-1	4	0%	100%
69	138 KV NEWCHURC-PINEYGRO 13764 138 KV COSTEN-KINGSCRK 13714-2	4	0%	100%
70	138 KV NSEAFORD-SHARRING 13771	3	0%	100%
71	SHARRING138 KV SHARRING AT-1 XFORMER	3	0%	100%
72	138 KV CHESWOLD-DOVERTAP 13775 230 KV CEDARCRE-MILFORD 23031	2	0%	100%
73	500 KV ALBURTIS-BRANCHBU 5016	2	0%	100%

Attachment C (PJM Congestion Report)
(Continued)

	Contingencies	Hours	% of Hours	Cum %
74	138 KV CEDARCRE-CLAYTON 13832 & 138 KV DOVERTAP-SHARRING 13704	2	0%	100%
75	138 KV LORETTO-VIENNA 13780 230 KV INDIANRI-PINEYGRO 23002	2	0%	100%
76	500 KV KEENEY-PEACHBOT 5014 500 KV HOPECREE-REDLION 5015	2	0%	100%
77	PINEYGRO138 KV PINEYGRO AT1 XFORMER	2	0%	100%
78	WYEMILLS138KV WYEMILLS AT-1 XFORMER	2	0%	100%
79	230 KV CHAMBERS-CHURCHTO 2313	1	0%	100%
80	230 KV INDIANRI-MILFORD 23069 230 KV STEELE-VIENA 23085	1	0%	100%
81	69 KV FRUITLAN-NSALISBU 6701	1	0%	100%
82	CEDARCRE230 KV CEDARCRE AT20 XFORMER	1	0%	100%
83	INDIANRI230KV INDIANRI 232 CB	1	0%	100%

Attachment D (PJM Congestion Report)

Calculating Congestion Cost from LMP Data

At any hour

The congestion cost at bus i is:

$$Cost_i = \sum_{m=1}^{constraints} Sh_m df_{i,m} L_i$$

$df_{i,m}$ Distribution factor of generation to load bus i for constraint m
L_i Load at Bus i

If there is only one constraint, m = 1 and the shadow price is the same everywhere

$$Cost_i = (Sh)(df_i)(L_i)$$

Bus load L_i can be expressed as a proportion "a" of zonal Load L_z

$$L_i = a_i L_z$$

The total cost is the sum of the bus costs

$$\boxed{Cost = \sum_{i=1}^{Buses} Cost_i = (Sh)(L_z)\sum_{i=1}^{Buses}(df_i)(a_i)} \quad \text{Equation 1}$$

The locational marginal price at any point j is

$$LMP_j = \sum_{m=1}^{constraints} Sh_m df_{j,m}$$

$df_{j,m}$ Distribution factor of generation to load bus j for constraint m

If there is only one constraint, m = 1 thus

$$LMP_j = (Sh)(df_j)$$

The congestion between points *j* and *k* is

$$LMP_j - LMP_k = (Sh\ )(df_j - df_k)$$

Therefore

$$\boxed{Sh\ = \frac{LMP_j - LMP_k}{(df_j - df_k)}} \qquad \text{Equation 2}$$

Combining equations 1 and 2, for any constraint between points *j* and *k* the congestion cost is

$$\boxed{Cost = \left[\frac{LMP_j - LMP_k}{(df_j - df_k)}\right](L_z)\sum_{i=1}^{Buses}(a_i)(df_i)} \qquad \text{Equation 3}$$

This is the equation used for the constraint cost calculations. In the Delmarva Peninsula study

- The constraint points *j* and *k* are the buses at each end of the constraints during the study period. 50 flowgates (monitored element / contingency combinations or "events") were selected for analysis, representing 95% of the total constrained hours from August 1, 1999 to August 10, 2002. When outages were in effect during a DPL constraint hour these outages were represented as additions to the 50 "no outage" flowgates. This increased the number of flowgates used to 238.

- L_z is the hourly DPL zonal load as published at www.pjm.com.

- $\sum_{i=1}^{Busses}(a_i)(df_i)$ is the load distribution factor on each flowgate. It was calculated by a transfer of all PJM generation to DPL load in the peak load power flow case using the PTI MUST™ software. This implies that all PJM generation responds in proportion to its size (P_{max}) to serve increasing (or decreasing) load in *pro rata* proportion as modeled in the power flow case.

- LMP's are chosen to be as "close" to the constraint points as possible. They can generally be identified by picking the lowest and highest LMP's for hours where the constraint in question was the only one in effect at that hour. In the event such points are not evident the average LMP difference between points over the total LMP record was used to pick "equivalent" LMP points.

- The flowgate distribution factors df_j and df_k are calculated by a shift of all PJM generation to the constraint buses *j* and *k*. The power flow buses are chosen to be those of the constraints as closely as possible. Calculations were performed with the PTI MUST^{TM} software.

The calculation proceeded by use of equation 3 for each hour. The total constraint cost is the simple sum of the cost for each hour

Attachment D
PJM Delmarva Peninsula Congestion Presentation

PJM Interconnection

Delmarva Congestion Study

William H. Whitehead
Manager-Transmission and Interconnection Planning
PJM Interconnection, L.L.C.

November 7, 2002

PJM Interconnection

Delmarva Congestion Analysis - Background Information

- **Time Period 8/1/99 to 8/11/02 (26,568 hours)**
- **Congestion Cost for DPL Zone Only Constraints**
- **Congestion Cost in the Real Time Market**
- **Calculate Total Cost and Cost per Constraint**
- **Attribute Cost per Constraint to**
  - **Construction (Upgrades and Plant Tie-ins)**
  - **Forced Maintenance**
  - **Planned Maintenance**
  - **No Outages (Load or Dispatch related)**
- **Sum by Year and Outage Type**

Delmarva Congestion Analysis - Background Information

- 26,568 hours studied
- 179 DPL constraint events (monitored element/contingency combination)
- 6,762 hours of DPL constraining events
  - Up to 5 Simultaneous Constraints
  - Average 1.2 constraints
- 540 DPL zone outages
  - 30 minutes to 231 days
  - 212 outages $\geq$ 24 hours
  - 2/3 of constrained hours had concurrent transmission outages
  - Up to 12 Outages per Constrained Hour
  - Average 4 Outages per Constrained Hour

Delmarva Congestion Analysis - Calculation Approach

Calculation Approach - Method 1 Total Zonal Congestion Cost

- Use DPL and PECo zones as reference
- Congestion Cost is Zonal Price Difference Times DPL Zonal Load
- Does Not Include Cost Increasing Effect of Constraints Outside DPL Zone (Eastern Interface most important)
- Cannot Allocate Zonal Cost to Simultaneous DPL Constraints
- Very Difficult to Relate Zonal Cost to Outage Effect and % of Load Affected

Delmarva Congestion Analysis - Calculation Approach

Calculation Approach - Method 2 Shadow Prices

- **Shadow Price – Cost of Relieving a Constraint**
- **Constraint Congestion Cost = Shadow Price x Load Affected**
- **Total Cost is Sum of Individual Constraint Costs**
- **Shadow Prices Not Available**

Delmarva Congestion Analysis - Calculation Approach

Estimate Shadow Prices and Load Affected

- **Shadow Price Estimation**
  - **From LMP's at the Constraint and Distribution Factors**
- **Load Affected From Distribution Factors**
- **Most Important Assumptions**
  - **Constraints are Independent Effects on LMP**
  - **All PJM Generation is the incremental Supply**
  - **All DPL Load Responds *pro rata***
- **Assumptions Imposed to Simplify Calculation**
  - **Top 50 Constraining Events**
  - **One Network Topology (RTEP power flow case)**
  - **Outages $\geq$ 24 hours (96% of all outage hours)**

Delmarva Congestion Analysis - Calculation Approach

Estimate Shadow Prices and Load Affected

- **Key Computation Aspects**
  - **50 Most Frequent Constraining Events (86% of all constraint hours)**
  - **337 Event / Outage Combinations (Network Topologies) Simulated**
  - **7,089 Hours Analyzed**
- **Multiple Constraint Interaction Minimized by LMP and distribution Factor Location Selection**
- **Including Outage Effect is Critical**

Delmarva Congestion Analysis - Preliminary Results

- **Constraint Congestion Cost / Hour**
  - **$90,550 to $250 per hour**
- **Constraint Shadow Prices**
  - **$430 to $15 per MWHr**
- **Constraint Load Impacted**
  - **1135 MW to 10 MW**
- **Constraint Frequency Was a Bad Predictor of Congestion Cost**
- **Cost Depends on Shadow Price and Load Impacted**

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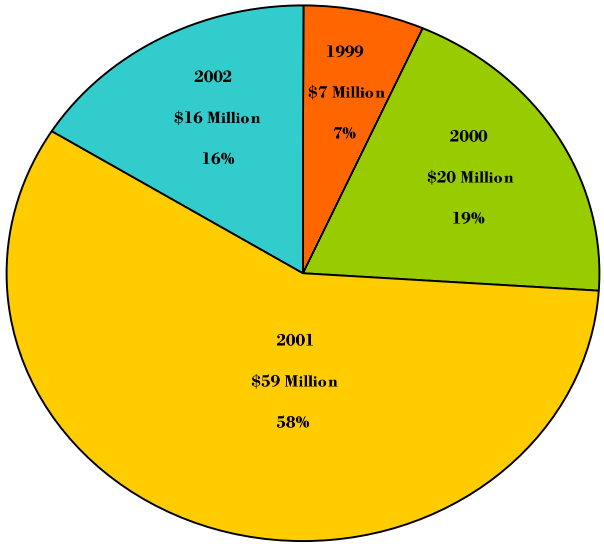
Delmarva Congestion Analysis - Preliminary Results

**Summary of Congestion $'s by Year
August 1999 - August 2002**



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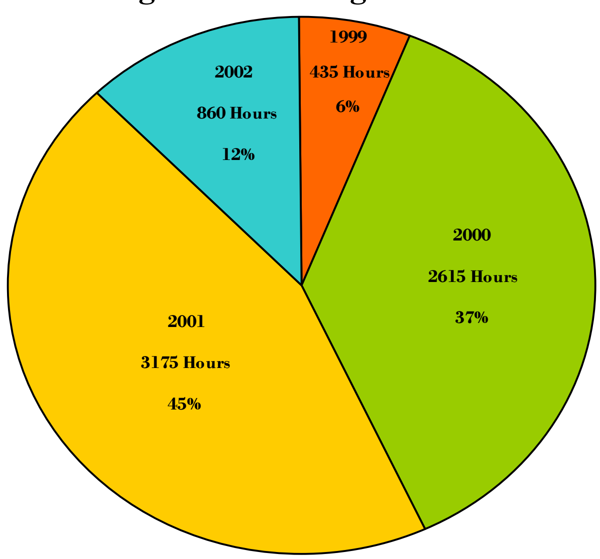
Delmarva Congestion Analysis - Preliminary Results

**Summary of Congestion Hours by Year
August 1999 - August 2002**



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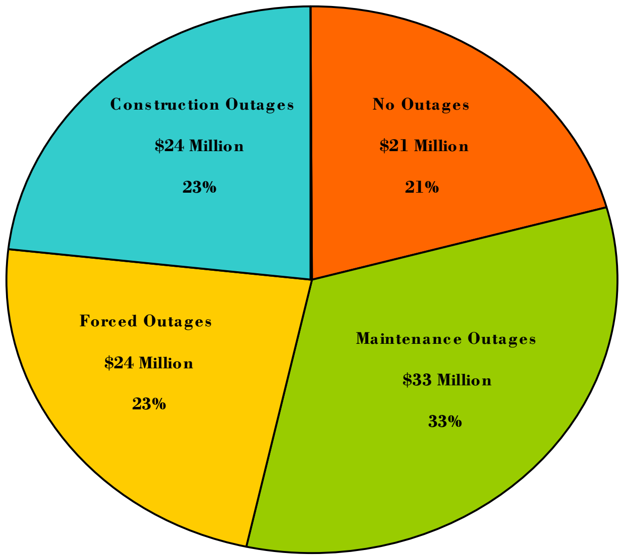
Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion $'s by Cause
August 1999 - August 2002



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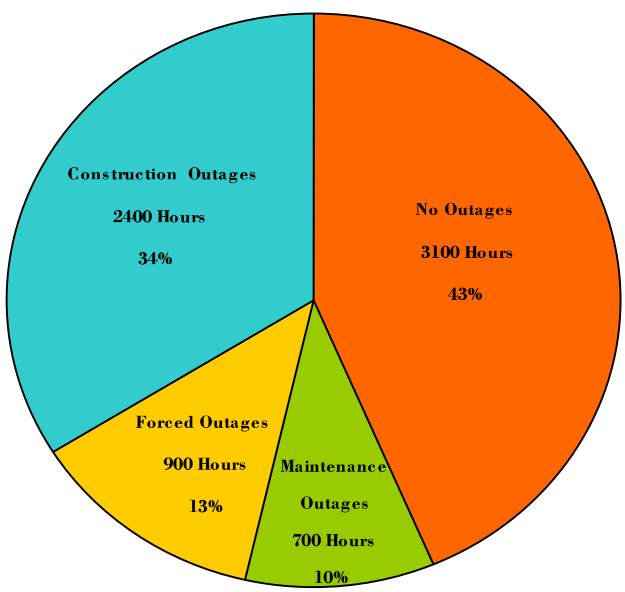
Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion Hours by Cause
August 1999 - August 2002



Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion Causes by Hour
August 1999 - August 2002

- **Mt. Olive - Piney Grove 69 kV** — 23% of all hours (1650 hours)
  - related to construction outages
- **Hallwood - Oak Hall 69 kV & Oak Hall - Tasley 69 kV** — 22% of all hours (1550 hours)
  - related to load
  - 69 kV CB significantly reduced congestion
- **Interface DPL South** — 7% of all hours (500 hours)
  - two SVCs (Indian River & Nelson)
  - upgrade of Steele - Vienna 138 kV to 230 kV
- **Easton - Trappe Tap 69 kV** — 6% of all hours (450 hours)
  - congestion eliminated through upgrade

Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion Causes by Hour
January 2002 - August 2002

- **Hallwood - Oak Hall 69 kV** — 23% of all hours (200 hours)
  - related to load
- **Cheswold 138/69 kV transformer** — 21% of all hours (180 hours)
  - Various drivers
- **Church 138/69 kV transformer** — 14% of all hours (120 hours)
  - Load and generation related
- **Indian River 230/138 kV transformer** — 10% of all hours (85 hours)
  - Load and generation related
- **Keeney 230/138 kV transformer** — 9% of all hours (75 hours)
  - Load and generation related

Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion Causes by $'s
August 1999 - August 2002

- **Keeney 500/230 kV** — **27% of all $'s ($27 million)**
  - related to maintenance outage
- **Interface DPL South** — **16% of all $'s ($16 million)**
  - two SVCs (Indian River & Nelson)
  - upgrade of Steele - Vienna 138 kV to 230 kV
- **Mt. Olive - Piney Grove 69 kV** — **13% of all $'s ($13 million)**
  - related to construction outages
- **S. Harrington - Bridgeville 69 kV** — **10% of all $'s ($10 million)**
  - related to maintenance outage

Delmarva Congestion Analysis - Preliminary Results

Summary of Congestion Causes by $'s
January 2002 - August 2002

- **Cheswold 138/69 kV transformer** — **33% of all $'s ($5.5 million)**
  - Various drivers
- **Church 138/69 kV transformer** — **26% of all $'s ($4.5 million)**
  - Load and generation related
- **Keeney 230/138 kV transformer** — **17% of all $'s ($2.8 million)**
  - Load and generation related
- **Indian River 230/138 kV transformer** — **7% of all $'s ($1.2 million)**
  - Load and generation related

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Attachment E
Old Dominion Market Pricing Alternative

Old Dominion proposes for a short-term solution to develop a transparent mechanism for an RTO/ISO to mitigate local market power. The mechanism must mitigate local market power without distorting the prices paid to generating units that do not possess local market power and must provide the strongest possible incentives for all generation unit owners to bid as close as possible to their minimum marginal cost supply during all system conditions. The mechanism Old Dominion proposes satisfies the following three criteria:

* It recognizes that initial conditions in the transmission network of a wholesale market using Locational Marginal Pricing (LMP) can lead to significant consumer harm through extremely high electricity prices at certain locations in the transmission network. This harm occurs because of the transmission and generation infrastructure decisions by the former vertically integrated monopolist to serve a market structure that no longer exists. A high cost area to serve may result from these prior decisions. Had the monopolist chosen a different strategy to serve its load, some of these areas could instead be low cost areas.
* The market mitigation mechanism must recognize the inter-relationship between the markets in which the generation unit owners can participate and,
* It should not allow generation unit owners to use this mechanism to distort market outcomes in their favor.

The market mitigation mechanism proposed by Old Dominion incorporates local market power mitigation in the spot market and local market power in the forward congestion management market. It excludes from the LMP process bids from generation units for only their pivotal quantity of energy. This pivotal quantity must be supplied regardless of how much the unit bids or demand is not served. For this reason, it is better to think of this amount of energy as a constraint on the feasible dispatch process, because it must operate or the lights go out, similar to any other network constraint. There is no economic decision about the price at which to take this amount of energy. It is an engineering constraint. In addition, this local market power mitigation mechanism prevents cost-of-service regulated bids from being combined with market-based bids on the LMP process, thereby limiting the ability of generation unit owners with local market power to leverage this market power to all of the units they own.

The market mitigation mechanism proposed by Old Dominion requires that at the close of the day-ahead market, after all generation unit owners submit their willingness to supply during each hour of the following day, the RTO/ISO would first estimate the State of the transmission network the following day and the level of demand at each location in the network. The RTO/ISO would then determine the total amount of capacity bid into the day-ahead market at any price by each generation unit in the control area and all importers into and exporters out of the control area. To determine the extent to which each firm owning generation in the RTO/ISO's control area is a local monopolist, the RTO/ISO would solve for the minimum amount of generating capacity on a system-wide basis that must be committed in order for all physical network constraints to be satisfied given the RTO/ISO's best guess of demand at each location in the transmission network. It is key that in any approach to determine the pivotal quantity of energy, the RTO/ISO must incorporate the network constraints. Using the capacity commitments resulting from solving this optimization problem, the RTO/ISO would determine whether each firm was a local monopolist for a nonzero quantity of energy given the capacity commitments from generation units owned by all other market participants. The minimum quantity of energy over which a firm was a local monopolist, would then become the firm's pivotal quantity.

> The mechanism then requires that bids submitted by each of these firms for their pivotal quantity of energy would be mitigated. Mitigated bids would not be allowed to enter the LMP process, with the generators supplying the pivotal quantity of energy from the units the RTO/ISO had designated as having a nonzero pivotal quantity of energy. Payment to the generators could be the resulting locational marginal price at its location for the pivotal quantity instead of its variable costs or the generator could receive its variable costs. The choice would be the generators.
>
> Local market power also manifests itself in the forward congestion management market was well as the energy spot market. The ODEC proposed mitigation mechanism addresses this problem as well. The mechanism proposes to allocate Congestion Revenue Rights (CRR) among market participants in order to ensure that they are used to hedge against congestion costs, rather than be used to enhance the ability of generation unit owners to exercise market power. Congestion Revenue Rights benefit, to the greatest extent possible, load serving entities (LSE) that use them as a hedge against locational price differences between the LSE's source of power and the location where this electricity is withdrawn from the transmission network. Load uses CRRs as insurance against congestion charges that it cannot impact while generators can use CRRs as a source of revenue from congestion charges that it can impact by how it schedules or bids its units. This feature of CRRs is available only to generators because final load is perfectly inelastic with respect to demand changes.

Firms owning generation units would derive the greatest economic value from CRRs because they posses the flexibility to bid, schedule and operate their units to maximize the level and location of congestion in the transmission network. Depending on how they operate their units, generators can also increase the frequency and magnitude of the congestion revenues they receive. To counter this market behavior, Old Dominion proposes that CRRs should be allocated to load. Secondly, CRRs should be allocated to load on a annual basis to reflect load growth and new system improvements. Finally, the CRR allocation process should account for the fact that a generation-unit-owning LSE or one with long-term commitments from local generation units needs less CRR to achieve the same level of protection from congestion charges. More efficient local generation units would have a larger fraction of their capacity netted out against the LSE's local load obligations. The details of this allocation mechanism should differ across RTOs/ISOs depending on a number of factors such as the amount and location of hydroelectric power in the RTO/ISO control area(s) and the dependence of the RTO/ISO on imports to meet its load obligations.

Note, this is a different mechanism that is currently employed by PJM. First, the PJM ISO uses a different procedure for determining whether a generation unit owner possesses significant enough local market power to have its bid mitigated. Old Dominion supports the definition that any firm that is a monopolist for a non-zero quantity of energy in a local area must be mitigated for at least the pivotal quantity of energy. PJM mitigates the bid of a generating unit if the unit is run "out of merit order". PJM subjects the entire capacity of the unit to mitigation whereas Old Dominion supports mitigating only the pivotal quantity of energy. Finally, PJM allows the mitigated bids to enter the LMP process. Old

Dominion would not allow the "regulated" unit to set the price for the market based derived prices in the LMP process. Finally, PJM makes available CRR to load, but it does not net out CRR for LSEs that have local generation.

Attachment F
Distributed Resources

Status of Equipment and Industry

Reciprocating Engines are "old technology" but in the last few years microprocessor controls have yielded cleaner burning diesel and gas engines. Exhaust stream clean up technology is also becoming more cost-effective. Recent packaging upgrades on trailer mounted gensets has significantly reduced noise and objections to using units close to residential properties. New mobile gensets from CAT and Cummins have excellent relaying and remote control capability. Recips remain the cheapest generator source at about $200-300/kW for diesel and about twice that for gas engines.

Microturbines are not a totally new concept but developing a low maintenance, quiet, environmentally friendly and aesthetically packaged unit such as Capstone has done make them suitable for small industrial and commercial applications. The addition of CHP (Combined Heat and Power) capability help these units overcome an inherit weakness – poor efficiency. Sizes of 30kW, 60kW, 75kW are available and in the future 250kW. Costs vary with installation but are around $1350/kW for simple non-CHP installations and up to $2,500/kW for CHP system.

Wind turbines have found a niche for producing green power. Although they generally don't count for capacity, they can be looked at as an energy when located in the correct location. With subsidies and the ability to get a premium for producing green power, some units have been cost-effective to install. Recent upgrades in design and control allow some wind turbine generators to dynamically change the VAR output and interface better with ("less stiff") distribution feeders. Individual wind turbines now rise to height of 150 feet and can produce up to 1.5MWs per turbine. Cost is about $1050/kW to install. Total Energy cost is about 3.8-4 cents/kWH. Currently subsidies cover about 1.5-1.8 cents/kWH. Green premium paid by customer is about 15-30% over nominal cost of energy.

Fuel Cells have been under development for many years. UTC has had a 200kW unit they have been selling for the past 10-12years. Fuel Cells fit the niche where a customer needs premium power, has use for the waste heat and has a fuel source (natural gas preferred). Sizes can range from several kW to several MWs. Prices remain quite high – over $4,000/kW and penetration into the distribution grid very small. Portable electronics and hand held tools as well as vehicles are promising areas of use for the near term.

Photovoltaics are not new, but are getting more efficient. Although they can't be used for capacity, they do generally have peak output during peak electrical use periods and therefore are looked at as energy contributors. The power electronics package has improved significantly over the last few years and several small systems are pre-approved to be installed in our territory. At $6000/kW it remains one of the more costly DG options. Government subsidies have encouraged a few installations but it will probably not be cost-effective for many years to come, if ever.

A few other technologies such as Sterling engines, and combinations of the above clean technologies like fuel cells and microturbines round out the mix of generators. Storage devices such as flow batteries are showing promise for reducing system peak and relieving constrained feeders or distribution equipment.

History of DG Activity at Conectiv

1984-2000	Pilot Fuel Cell and PV Installations
1990s-	Operate DG Installations for Customers (Conectiv Energy)
1998	Generator Service Contracts (Atlantic Region, discontinued after 1 year)
1998	Capstone Investment through Enertech
1999-2002	Distribution Studies with DOE – Peninsula and Long Beach Island
2000	Residential Fuel Cell Project Proposed but not Pursued (Plug Power)
2000	Turnkey Customer Installations from Conectiv Solutions
2000	DG Dispatch Center Built at Conectiv Solutions
2000	Install 17MWs of Diesel Gen in Peninsula to back up Transmission System
2001	Install 5MWs of Diesel Gen at Beach Haven with EMS control
2001	Install 1.5MW DG unit at Chester River in emergency
2001	Review the concept of a DG Parking Lot
2002	Install 5MWs additional DG at West Creek Ops, Use phone & PC for control
2002	Begin design and installation of 2 – 60Kw Microturbines in CHP application
2002	Gave DG Presentations at EPRI, EEI and DOE conferences
Future	Two (2) micro-turbines and a mobile gas engine
Future	Mobile Flow Battery demo project

Attachment G
Other State Land Use Information

Pennsylvania-Public Utilities in Pennsylvania have the right to condemn property except within 300' of residential properties, but if there is a natural boundary such as a road or railroad that passes within this 300' area, then land can be condemned on the other side of the boundary even if within the 300' area. The utility will prepare alternatives routes and submit to the Public Service Commission. An Administrative Law Judge will be assigned to conduct hearings on the line. The utility will indicate their preferred route and the Judge will make a recommendation to the Commission based on the public hearings and pertinent information. The Commission usually accepts the recommendation and approves the project along with condemnation powers. The utility will continue to negotiate and will obtain appraisals of any properties that may need to be condemned. The utility will deliver a bond to the courts for the property value and construction can begin. The property owner can agree with the amount of money or they can appeal, but this does not stop construction. A County Board of View made up of three knowledgeable individuals will determine a final price on appeal and the utility will either pay the additional or could be refunded some of the bond.

New Jersey – Public Utilities in New Jersey have the right to condemn after being granted the authority by the Board of Public Utilities. Approval by the BPU also negates the impact of local zoning and land use ordinances. The utility will perform their normal route selection process based on cost, ease of obtaining permits, environmental, land use, right of way and whatever other factors they choose. After selecting the route, the utility will petition the BPU for approval to construct the line on the specified route. The BPU will conduct public hearings and accept input from all affected parties along the route. The utility will continue to negotiate for right of way while the BPU considers the request. Appraisals will be done for any right of way that will need to be condemned. Once the BPU approves the project, the utility will submit a separate petition to the BPU to have condemnation rights approved. Once approved, the utility will deposit the appraised value of the condemned property with the courts and construction can begin. Three commissioners (usually two attorneys and a realtor) will decide the final value of the right of way.

Maryland – Public utilities in Maryland have the right to condemn after being granted the authority by the Public Service Commission. For any construction **greater than 69,000 volts**, the utility must obtain a Certificate of Public Convenience and Necessity from the Public Service Commission. The utility will perform their normal route selection process to determine the best route. They will begin signing easements for the route and begin the necessary environmental permitting studies and investigations. After the utility has signed some of the right of way and determined the best route with the least public opposition, the utility will file for a Certificate of Public Convenience and Necessity with the Public Service Commission. The Public Service Commission will hold public hearings and will issue the Certificate if they approve. The utility now has the right to condemn, but in Maryland the condemnation process still involves the courts, so this can delay the start of construction.

Some States also have siting committees which contain members from the real eState profession, law profession, Public Service Commission Members and elected officials. An Administrative Law Judge may or may not head the commission. The utility will submit several possible routes and the siting committee will determine the best route. Along with the determination of best route comes the right to condemn.

Attachment H
PROPOSED CONGESTION MITIGATION PROCESS

Attachment 8a - Proposed Process for Planned Outage Congestion Mitigation

- Transmission Owner submits outage request in accordance with PJM requirements(4 to 8 weeks prior to outage)
- PJM posts outage on the PJM OASIS
- PJM updates outage information on OASIS at least two weeks prior to outage by flagging any outages that may result in significant congestion. PJM presently uses a rule-of-thumb for significant congestion as the need to start a unit not expected to be dispatched on economy. (Need more discussion with PJM on levels of congestion.)
- LSEs may contact the Transmission owner with respect to operational suggestions for mitigating congestion. Example: Moving load from one delivery point to another to lessen Transmission flows. Opening a transmission line to eliminate a possible overload provided there are no reliability risks. The Transmission owner will respond with reasons to accept or reject the suggestion. Suggestions need to be submitted to the Transmission Owner at least one week prior to the outage.
- The Transmission owner may contact an LSE with similar operational suggestions for mitigating congestion.
- The suggestion, in either case, must include specific switching and load estimates and be documented in writing.
- The LSE must follow through on the promised switching proposal on the day of the outage unless it would result in reliability problems.

Attachment I
PROPOSED 3RD PARTY CONGESTION CONTRIBUTION PROCESS

Attachment 8b - Proposed process for Third party contributions to mitigate congestion

- Establish a process that will allow/specify funding from third parties to Transmission Owners for reducing outage durations.
- Outage duration must be greater than 5 days or $100,000 in congestion costs and flagged by PJM on OASIS as potentially causing significant congestion.
- Third party contacts Transmission Owner in accordance with the established process at least 10 days prior to the start of the outage. PJM will need to provide at least two weeks advanced notification on OASIS of congestion impacts.
- Transmission owner responds with reasons for accepting or rejecting the proposal with estimated costs if accepting.
- Third party contacts Transmission Owner 3 days before the start of the outage to confirm that they wish to proceed with the funding to reduce the outage duration.
- Transmission owner notifies PJM through E-DART (outage submission tool) of the reduced outage time.
- After outage is completed the Transmission Owner bills the third party for increased labor costs per PJM ground rules.
- Needs to be a cost sharing mechanism to allocate increased costs.